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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Enhance  
the Role of Demand Response in Meeting  
the State's Resource Planning Needs and  
Operational Requirements.

Rulemaking 13-09-011  
(Filed September 19, 2013)

**ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS  
REGARDING THE COST-EFFECTIVENESS PROTOCOLS AND THE  
VALUATION WORKING GROUP REPORT**

**Summary**

This Ruling addresses proposals regarding the demand response cost-effectiveness protocols and demand response load modifying resources, as described below.

First, this Ruling summarizes draft revisions to the 2010 Cost-Effectiveness Protocols (Protocols) as proposed by Commission staff as well as the suggested revisions from the Load Modifying Resource Demand Response Valuation Working Group (Valuation Working Group). Second, the Valuation Working Group's compliance report and its recommendations for load modifying resources are discussed for further evaluation.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (collectively, the Utilities) shall, and other parties to this proceeding may, file comments on the draft 2015 Protocols and responses to specific questions contained in this Ruling. Comments and responses shall be filed no later than July 31, 2015, and replies shall be filed no later than August 14, 2015.

## **1. Procedural Background**

In December 2010, the Commission approved Decision (D.) 10-12-024, which adopted protocols for estimating the cost-effectiveness of demand response activities (Protocols). D.10-12-024 required the Utilities to use the Protocols for all future cost-effectiveness analysis of demand response activities, including the 2012-2014 demand response program applications.

Application (A.) 11-03-001 et al. was the first time the Commission utilized the Protocols to determine the cost-effectiveness of demand response programs. As such, the Commission was not surprised to find deficiencies in the Protocols.<sup>1</sup> However, the deficiencies described in D.12-04-045 do not indicate problems with the protocols so much as they denote misinterpretations or inconsistencies amongst the Utilities, as well as the Utilities' omission of qualitative analysis. The deficiencies are: 1) inconsistent and speculative results in determining the five factors for adjusting a demand response program's avoided costs; 2) an inconsistent approach amongst the Utilities for allocating the budgets of supporting programs (i.e. marketing, education and training; evaluation, measurement and validation; and information technology; and 3) the omission by the Utilities of any qualitative analysis of "optional" costs and benefits as directed by D.10-12-024.

D.12-04-045 required staff to hold one or more workshops to address the deficiencies of the 2010 Cost-Effectiveness Protocols.<sup>2</sup> As a result of an October 19, 2012 workshop, Commission staff developed the 2014 draft revised Protocols.

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<sup>1</sup> D.12-04-045 at 35-37.

<sup>2</sup> D.12-04-045 at Ordering Paragraph (OP) 7.

On June 23, 2014, a Ruling was issued in this proceeding providing the 2014 draft revision of the Protocols and asking for comments on the draft. On July 31, 2014, following the filing of a joint party proposal in Rulemaking (R.) 13-09-011, a Ruling was issued suspending the schedule for providing comments to the draft revised Protocols.

D.14-12-024 — as modified by D.15-02-007 — approved a majority of the joint party proposal and included the establishment of several working groups to develop solutions for enhancing the role of demand response in meeting California’s electric resource needs. One of the working groups, the Valuation Working Group was tasked with recommending how load modifying resources should be valued after 2018. The Valuation Working Group also looked to inform quantification of demand response values for the Protocols.<sup>3</sup> D.14-12-024 required the Valuation Working Group to file its recommendations to the Commission on May 1, 2015.

The proposed revisions to the Protocols and the recommendations from the Valuation Working Group report are described further below.

## **2. Overview of Staff-Recommended Revisions to the Protocols**

As a result of the workshop held on October 19, 2012, Commission staff has developed a red-lined draft 2015 revisions to the Protocols, attached to this Ruling as Appendix A. The Protocols have been further revised since the 2014 draft to account for additional recommendations by staff. In addition to the following specific recommendations, staff has also edited the Protocols to correct minor errors and provide clarifications.

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<sup>3</sup> D.14-12-024 at Appendix 1, Attachment B, p 1.

In response to the three concerns expressed in D.12-04-045, the 2015 draft Protocols recommend:

- A new model for the A factor and avoided generation capacity cost allocation, which replaces the utility calculation of the A factor (*see Section 3.B.1*);
- A new model for avoided Transmission & Distribution (T&D) costs (*see Section 3.B.3*), based on the model used in the Net Energy Metering (NEM) study, which replaces utility-submitted values for the avoided T&D cost;
- Refined definitions of the B, C, and D factors (*see Section 3.B.1*);
- Refined definitions and guidelines on the allocation of support program budgets (*see Section 3.A*), qualitative analysis (*see Section 1.G*) and the definition of the demand response portfolio (*see Section 1.H*); and
- A new requirement versus the current option of work papers in addition to the current required spreadsheets for reporting purposes (*see Section 1.G*).

In addition to addressing the issues discussed in D.12-04-045, the October workshop participants also addressed other concerns with the 2010 Protocols. Staff has proposed additional refinements to the Protocols to address these concerns, including:

- In analyzing the cost-effectiveness of supply resource demand response, the Utility shall use only the avoided cost section of the Protocols (*see Sections 1.A and 3.B*);
- The creation of two new factors: F (flexibility) and G (geographic) factors. The F Factor is an optional adder that the Utilities may propose for demand response programs that provide those benefits. The G Factor is a new geographic benefit adder to account for locational value of capacity in transmission-constrained areas (*see Section 3.B.1*);

- Changes regarding non-energy benefits (NEBs) including: 1) the revision of definitions of NEBs, which conform with current definitions in the literature, 2) the deletion of the category of “environmental benefits,” because environmental benefits are considered a type of NEB, and 3) the clarification of which Standard Practice Manual test allows which types of NEBs (*see Section 3.J*);
- The addition of a section regarding dual participation (*see Section 1.I*);
- A revised calculation of capital costs: the high value used in the sensitivity analysis is the total cost amortized over the 3 year budget period, the low value used in the sensitivity analysis is the total cost amortized over the equipment lifetime, and the base value is the halfway point between them (*see Section 3.E and Section 3.F*);
- The addition of a new requirement that the Utilities provide *ex post* cost-effectiveness analysis as part of their evaluation process (*see Section 1.A*);
- A revised participant cost definition for air conditioning cycling programs (*see Section 3.M*); and
- The incorporation of relevant sections of previous (January 2011 and May 2012) Commission staff guidance documents (throughout the Protocols).

Finally, over the course of the past year, Commission staff has been working with stakeholders on the topic of cost-effectiveness in other Commission proceedings, including the NEM proceeding where a recent version of the E3 Avoided Cost Calculator was used for the NEM Ratepayer Impacts Evaluation.<sup>4</sup> As a result, Commission staff has proposed two additional policy refinements to the Protocols:

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<sup>4</sup> The calculator is available at [http://www.cpuc.ca.gov/PUC/energy/Solar/nem\\_cost\\_effectiveness\\_evaluation.htm](http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm).

- In analyzing the cost-effectiveness of resources, load serving entities shall use the most recent version of the E3 avoided cost calculator (*see Sections 1.A and 3.B*); and
- If a load serving entity cannot determine reasonable values for the G factor, then default values, as proposed by staff, will be used (*see Section 3.B*).

### **3. Overview of Valuation Working Group Report**

On May 1, 2015, the Valuation Working Group filed its report in compliance with OP 4.f.ii. of D.14-12-024. A matrix of the recommendations is attached to this Ruling as Appendix B. The Working Group Report describes recommendations which directly relate to the Protocols and others which do not. Here we address each of these categories in turn.

With respect to the Protocols, the Valuation Working Group was to recommend how the load modifying resources will be valued for setting and informing demand response cost-effectiveness determination. Specifically, the working group looked at informing the quantification of demand response values for the cost-effectiveness protocols. The report makes two overall recommendations.

First, the working group recommends that the A Factor should be modified to incorporate the LOLP/LOLE (loss of load probability/loss of load expectation) approach using publicly available information and more accurately quantify the capacity value of demand response programs by more accurately reflecting the value of the highest peak hours.

Second, the working group recommends creating a process for valuing load modifying resources for transmission and distribution benefits and incorporating that process into the Protocols. For the near term, the working group recommends that each utility calculate a dollar/Kilowatt (kW) locational avoided cost for each project where a load modifying demand response program

may contribute to project mitigation either as a stand-alone solution or as part of a portfolio of solutions. Additionally, the working group also recommends that the amount of locational avoided cost credited to each kW of load modifying demand response load impact will be determined by calculating the effective load carrying capacity of the load modifying demand response program, or its equivalent.

The working group also makes recommendations that are related to valuation, but are not a part of the Protocols. Some of those recommendations are best taken up in the Resource Adequacy proceeding and some will be reviewed in this proceeding for determination in a future decision. In summary, the recommendations to be reviewed in this proceeding include:

- Whether and how to establish hard triggers for the dispatch of demand response programs not integrated into the wholesale market (non-event Load Modifying Resources);
- Whether and how to establish a nomination and penalty framework through which Utilities would avoid costs through reducing effected metrics; and
- Enhancements to the demand response load impact protocols.

We will address these three recommendations in parallel to our consideration of changes to the Protocols.

#### **4. Discussion**

As detailed above, Commission staff and the Valuation Working Group have made several recommendations for revising the 2010 Protocols. The Valuation Working Group has also made recommendations regarding load modifying resources, as discussed in this Ruling. In order to make a determination on the proposed recommendations, the Commission needs party input. Hence, as further described below, the Utilities shall, and parties may,

provide comments to the draft revision of the Protocols and to the discussed recommendations of the Valuation Working Group.

First, in regards to the changes to the 2010 Protocols, the Utilities are instructed to comment on each of the Protocol revisions described earlier in this Ruling. Other parties on the service list are also invited to comment on Staff and Working Group proposed changes to the Protocols. In addition to the proposed revisions previously discussed in this Ruling, all parties should also respond to the following questions related directly to the Protocols:

1. Is the latest version of the E3 Avoided Cost Calculator consistent with the revised Protocols? If not, what language changes are necessary and why;
2. How does the method, proposed by the Valuation Working Group, for determining the value that certain demand response projects have in avoiding the cost of distribution system updates fit into the Protocols? Parties should explain if and how this method will be used to determine the D Factor discussed in Section 3.B of the draft 2015 Protocols, or if this method constitutes an alternative to the proposed avoided T&D cost model, or a combination of both. Parties should provide specific language for modifying the text of the draft 2015 Protocols to convey their response;
3. Are the Valuation Working Group's proposed changes to the A Factor consistent with the draft 2015 Protocols or are additional language changes to the draft 2015 Protocols required? If changes are required, parties should provide specific language modifying the text of the draft 2015 Protocols; and
4. Are additional language changes to the draft 2015 Protocols required to convey other recommendations by the Valuation Working Group? Specific and detailed language should be provided.

Additionally, in regards to the draft 2015 Protocols, the Utilities are instructed to include in their comments a proposed plan to implement the final adopted 2015 Protocols. Parties may also comment on the implementation of the Protocols. The proposed implementation plan shall address the following:

1. How updates or adjustments should be made to the Protocols in order to insure consistency with the final adopted Protocols;
2. Whether and how the existing demand response reporting template should be revised or replaced in order to produce the demand response cost-effectiveness report spreadsheet (see Section 1B) and accompanying forms;
3. How the Utilities will work with Commission staff to translate the details of the Protocols to accomplish items 1 and 2; and
4. Whether additional funding is necessary to accomplish items 1 and 2. If so, how much funding is likely to be needed. If additional funding is necessary, what the process and schedule would entail.

Second, the Valuation Working Group presented its recommendations regarding load-modifying resources in its report. As described previously, this Ruling focuses on three aspects of the report: hard triggers for the dispatch of non-event Load Modifying Resources; a nomination and penalty framework; and enhancements to the demand response load impact protocols. The questions below are posed in order to provide further details to the Commission such that final determinations can be made on the report recommendations.

The Valuation Working Group proposes to create hard triggers but explained that there was no consensus on how to establish the hard triggers. The working group requests additional time to develop and perform a study on hard triggers. Alternatively, a smaller subset of the Valuation Working Group included in the report a proposal on how to set the hard triggers. D. 14-12-024,

Ordering Paragraph 4.f.ii states that “given the necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by May 1, 2015.” The expectation by the Commission was that the May 1, 2015 report would be a final report. This Ruling will therefore move forward with a focus on the CAISO hard trigger proposal. Hence, the role of the Valuation Working Group is considered to be complete and the request to perform the hard trigger study, as well as the study on the ability of load modifying demand response to avoid local capacity, is denied.

The Utilities shall, and parties may, respond to the following questions regarding the three aspects of the Valuation Working Group report;

1. The Commission may use the criteria listed (a-e) below to evaluate the CAISO hard trigger proposal. Are these criteria comprehensive? What should be the relative weight assigned to each criteria;
  - a) The effectiveness of the proposal in implementing adopted Commission objectives for demand response, especially in completing bifurcation by 2018;
  - b) The practicality of implementation of the proposal, including the recommended hard triggers, adaptation of load forecasting practices of the California Energy Commission, and adoption of a nomination and penalty framework to effectuate to proposal;
  - c) The potential impact of hard triggers on participation in and value of existing demand response programs;
  - d) The risk of unintended consequences; and
  - e) The potential for unforeseen benefits.
2. Under CAISO’s hard trigger proposal, how many events and hours would each existing demand response program be triggered if CAISO’s proposed hard triggers had been in

- effect between January 1, 2012 and the present? When would those events have occurred;
3. In order to consider the sensitivity of CAISO's day-ahead forecast in prompting dispatch pursuant to CAISO's proposed hard triggers, please execute the same analysis used to answer question 2 at the following thresholds: 90 percent, 95 percent, 105 percent and 110 percent of CAISO Day Ahead Forecast;
  4. The deviation from CAISO Day Ahead forecast required to reach 10 percent, 20 percent, 50 percent, and 100 percent of the programs available hours. For example, if the hard trigger was X percent and Y percent of CAISO Day Ahead Forecast, AC Cycling would be dispatched 90 hours and 180 hours, respectively;
  5. The CAISO's proposal appears to result in a high amount of calls in April/May and September/October. How can the proposal be revised to provide more hard triggers during the heart of the summer demand response season (June-August);
  6. How can demand response providers test the hard triggers proposed by the CAISO;
  7. The concept of "new entry value" is raised in the non-compliance column of the CAISO's hard trigger proposal on p. 97 of the Valuation Working Group's report (Appendix 5.1). Define "new entry value" and its components;
  8. Provide a more explicit penalty structure for instances of a demand response provider not complying with hard trigger calls for a) Short-Term Avoided System Generation Capacity, b) Long-Term Avoided System Generation Capacity, and c) Avoided Flexible Capacity. Quantify historical examples of the proposed penalties. Provide a comparison to existing penalties for non-performance in CAISO markets;

9. What, if any, orders are needed by the Commission to implement the nomination process envisioned in CAISO's proposal;
10. What specific action would be required of the California Energy Commission to implement the nomination process envisioned in CAISO's proposal; and
11. What, if any, orders should the Commission make to implement the penalty framework envisioned in CAISO's proposal?

Responses to these questions along with general comments to the attached draft revision of the Cost-Effectiveness Protocols and the changes proposed by the Valuation Working Group shall be filed no later than July 31, 2015. Reply comments shall be filed no later than August 14, 2015.

**IT IS RULED that:**

1. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each file comments addressing the specific questions regarding the attached draft 2015 Cost-Effectiveness Protocols, as discussed herein, and include an implementation plan as instructed in this Ruling. Comments should also address the specific questions regarding the recommendations proposed by the Valuation Working Group. Opening comments are due no later than July 31, 2015, and reply comments no later than August 14, 2015.

2. Other parties on the service list of Rulemaking 13-09-011 may file comments to the attached draft 2015 Cost-Effectiveness Protocols and the recommendations proposed by the Valuation Working Group, as discussed herein. Parties are also invited to provide comments on a Protocols implementation plan and responses to the specific questions asked in this Ruling.

Opening comments are due no later than July 31, 2015 and reply comments no later than August 14, 2015.

Dated June 19, 2015, at San Francisco, California.

/s/ KELLY A. HYMES  
Kelly A. Hymes  
Administrative Law Judge


## **APPENDIX A**

### **2014 Revised Demand Response Cost Effectiveness Protocols**

**Energy Division Staff Proposal  
April 25, 2014  
updated June 2015**

2014 Revised Demand Response  
Cost Effectiveness Protocols

Energy Division Staff Proposal  
April 25, 2014  
updated June 2015



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### **List of Abbreviations**

AMI – Advanced Metering Infrastructure (i.e., Smart Meters)  
AS – Ancillary Services  
CAISO – California Independent System Operator  
CCGT – Combined Cycle Gas Turbine  
CEC – California Energy Commission  
CPUC – California Public Utilities Commission  
CT – Combustion Turbine  
DG – Distributed Generation  
DR – Demand Response  
DRAM – Demand Response Auction Mechanism  
E3 – Energy and Environmental Economics (consulting firm)  
ED – Energy Division (of the CPUC)  
EE – Energy Efficiency  
EM&V – Evaluation, Measurement & Verification  
GHG – Greenhouse Gas  
IOU – Investor-owned utility (usually refers to PG&E, SCE, and SDG&E collectively)  
IRP – Integrated Resource Planning  
ISO – Independent System Operator  
IT – Information Technology  
kW – kilowatt  
kWh – kilowatt-hour  
LI – Load Impacts  
LMP – Locational Marginal Price  
LOLE/P – Loss of Load Expectation/Loss of Load Probability  
LSE – Load-Serving Entity  
LTTP – Long-term Procurement Plan  
ME&O – Marketing, Education and Outreach  
MW – Megawatt  
MWh – Megawatt-hour  
NOAA – National Oceanic and Atmospheric Administration  
NPV – Net Present Value  
NQC – Net Qualifying Capacity  
NYMEX – New York Mercantile Exchange  
PAC – Program Administrators Test  
PG&E – Pacific Gas and Electric Company  
RA – Resource Adequacy  
RIM – Ratepayer Impact Measure  
SCE – Southern California Edison Company  
SDG&E – San Diego Gas & Electric Company  
SPM – Standard Practice Manual  
T&D – Transmission and Distribution  
TRC – Total Resource Cost  
WACC – Weighted Average Cost of Capital

## SECTION 1: BASIC INFORMATION

### **Introduction**

These 2014 revised Demand Response (DR) Cost-Effectiveness Protocols (2014 Protocols) provide a method for measuring the cost-effectiveness of demand response programs. These protocols are intended for *ex ante* evaluations of demand response programs which provide long-term resource value.

The 2014 Protocols are an updated version of the DR Cost-Effectiveness Protocols approved in 2010 in Decision (D.) 10-12-024 (2010 Protocols<sup>1</sup>). In addition to updating the 2010 Protocols, these 2014 Protocols incorporate the relevant sections of two guidance documents: the January 2011 Energy Division Guidance on Cost-Effectiveness<sup>2</sup> and the May 2012 Energy Division Guidance on Cost-Effectiveness<sup>3</sup>.

The 2010 Protocols were based largely on three previous proposals filed in Commission Rulemaking (R.) 07-01-041: the cost-effectiveness framework submitted by the three large California investor-owned utilities (IOUs) – Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (Joint IOU Framework),<sup>4</sup> the Demand Response Cost-effectiveness Evaluation Framework submitted by the Consensus Parties (Consensus Parties Framework),<sup>5</sup> and the Staff Draft Demand Response Cost-Effectiveness Protocols filed as Attachment A of the April 4, 2008 ruling in R.07-01-041.<sup>6</sup> Both the 2010 Protocols and the 2014 Protocols are designed for the three Investor-Owned Utilities (IOUs). Nevertheless, they should be applicable to demand response programs developed by any Load Serving Entity (LSE). However, LSEs other than the three IOUs are likely to require additional guidance.

These protocols have been developed with the understanding that DR is in a transitional period. Historically, DR was largely employed for reliability purposes during system emergencies in the form of interruptible programs for large industrial customers, which could be triggered when the California Independent System Operator (CAISO) would otherwise have to shed load during a system emergency or when a utility was faced with a serious distribution system

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<sup>1</sup> [http://www.cpuc.ca.gov/NR/rdonlyres/B6E241E0-5B38-4E6D-AC3B-18F70EC83246/0/2010\\_DR\\_CostEffectiveness\\_Protocols.pdf](http://www.cpuc.ca.gov/NR/rdonlyres/B6E241E0-5B38-4E6D-AC3B-18F70EC83246/0/2010_DR_CostEffectiveness_Protocols.pdf)

<sup>2</sup> <http://www.cpuc.ca.gov/NR/rdonlyres/92C54F59-8D88-446A-846A-1747628C0F33/0/GuidanceJanuary2011.pdf>

<sup>3</sup> <http://www.cpuc.ca.gov/NR/rdonlyres/FD11FEED-C322-4164-8EFC-ABE6F188ABDA/0/GuidanceMay2012.pdf>

<sup>4</sup> *Revised Straw Proposals For Demand Response Load Impact Estimation And Cost-effectiveness Evaluation Of Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E) and Southern California Edison Company (U 338-E)*, filed September 10, 2007 (<http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf>)

<sup>5</sup> *Joint Comments Of California Large Energy Consumers Association, Comverge, Inc., Division Of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) and The Utility Reform Network Recommending a Demand Response Cost-effectiveness Evaluation Framework*, filed September 19, 2007 (<http://docs.cpuc.ca.gov/efile/CM/75556.pdf>).

<sup>6</sup> *Draft Demand Response Cost-effectiveness Protocols* <http://docs.cpuc.ca.gov/efile/RULINGS/80858.pdf>

emergency. These customers generally shut down all, or at least a large part, of their operations during DR events.

However, the deployment of advanced metering technology and development of new energy markets is enabling greater use and flexibility of demand response by all types of customers. Increasingly, customers are able to manage their loads to provide different levels of load reduction in response to price signals or other incentives. These load reductions provide value to the grid not only during emergencies, but also during times of high energy prices or in the ancillary services market. Increased use of automated technology has made DR less dependent on customer behavior and, as a result, more consistent, reliable, and easier for customers. These changes means that DR is becoming something that more and more ratepayers can participate in, including residential customers, even when they can reduce only a small amount of load.

In addition, the increased amount of renewable generation due to Renewable Portfolio Standard (RPS) requirements means that there is increasing need to mitigate the impact of intermittent generation. Demand response resources can be used for this if they are designed to be flexible, with short notification and response times, and local availability.

Because of these emerging potential new uses of DR, the methods we use to measure its costs and benefits must be flexible enough to capture these emerging benefits.

The purpose of these cost-effectiveness protocols is to:

- Address the broad variety of DR programs, including current and future activities;
- Identify all relevant inputs that are important for determining the cost-effectiveness of DR;
- Establish methods for determining the value of those inputs; and
- Determine a useable overall framework and methods for evaluating the cost-effectiveness of each of the different types of DR activities.

The protocols presented here are not intended to address the following issues, which are more appropriately addressed in the course of the various Commission proceedings related to DR:

- Identification of proceedings where DR cost-effectiveness protocols will be used;
- The means by which the Commission will use these protocols to determine whether to pursue various DR programs, activities or policies;
- Consistency between load impact measurements for DR cost-effectiveness and the rules for determining whether a resource counts for resource adequacy; or
- Demand response program rate design and tariff terms and conditions.

The 2010 Protocols were used for the first time for the Demand Response 2012-2014 budget Applications filed by PG&E, SDG&E, and SCE in Application (A.)11-03-001 et al. The final Decision in that proceeding (D.12-04-045) found that there were some deficiencies in the 2010 Protocols, based on problems encountered during the proceeding, and directed staff to hold workshops and update the protocols accordingly. The problems found were:

- Inconsistency among the IOUs' calculation of the five adjustment factors (i.e., A, B, C, D, and E factors), particularly the A factor. This problem could be remedied by modifying the protocols to provide more specific definition of how to calculate these factors.
- Inconsistency among the IOUs' allocation of support program budgets such as ME&O, EM&V, and IT to each DR program. This problem could be remedied by modifying the protocols to provide more specific instructions of how to allocate these budgets.
- IOUs' lack of qualitative analysis of the optional costs and benefits. This is not a deficiency in the protocols, but rather lack of compliance by the IOUs. This problem could be remedied by modifying the protocols to provide more guidance on how to go about providing qualitative analysis.

The Decision also noted that there was both a lack of definition of the DR portfolio and inconsistency among the IOUs' perceptions of what should be included in the DR portfolio. The Decision asked that the Protocols be updated to include this definition. In addition, the Decision also directed that future DR Applications consolidate, as much as feasible, all DR related costs.

The modifications included in these 2014 Protocols address these, as well as other, issues in an effort to provide better guidance to LSEs.

### **Section 1.A: Intended Use of Protocols**

These protocols are intended for determining the cost-effectiveness of both individual DR programs and an LSE's overall DR portfolio. As noted previously, the Commission will determine the applicability of these protocols for DR programs. LSEs are typically required to file cost-effectiveness analysis for each DR program. A DR program is defined as any demand response activity which has measurable load impacts for which the LSE is requesting budget approval. This includes DR programs of all types – event-based and non-event based, price-responsive and emergency, day-ahead and day-of. They may be used for rate programs, such as Critical Peak Pricing, to determine whether a program, given a particular rate structure, is cost-effective. They will also be used to evaluate third-party aggregation proposals, whether they are supply resources or load-modifying resources. However, only certain portions of these protocols apply to those third-party aggregation proposals (or any other DR programs) designated as a supply resources, as explained below.

These protocols will be partially applied to supply resource demand response, which is integrated into CAISO markets. In particular, the avoided cost calculation, as discussed in Section 3.B., provides a way to benchmark both the value of DR products as compared to traditional generation and the relative value of different types of DR products, which often have different hours, days and months when they are available, different limitations on when they can be dispatched, and different participant notification requirements. The methods discussed in Section 3.B. provide a basis for the calculation of avoided cost benchmarks by which to judge the reasonableness and cost-effectiveness of capacity procurement bids and contracts procured pursuant to the proposed Demand Response Auction Mechanism (DRAM) proposal. ~~This reasonableness review is independent of any capacity cost cap calculation detailed in the DRAM proposal, and the avoided costs will not be used to calculate the cap. These avoided cost benchmarks will be calculated for each DRAM bid and contract consistent with the seasonal and~~

~~hourly availability and other characteristics contained within each bid.~~ The IOUs will provide an avoided cost benchmark for each selected DRAM contract and bid confidentially with the Commission as part of their Advice Letters seeking Commission approval of DRAM procurement contracts. That analysis will consist only of the above-described benchmark, determined by the Avoided Cost model and other methods and models, including the adjustment factors, discussed in Section 3.B. Other costs and benefits listed in these protocols will not be applied or used as part of the reasonableness review of supply resource demand response. The DR Cost-Effectiveness Report, discussed below, will be modified to provide these avoided cost benchmarks for supply resources.

These protocols may not be fully applicable to permanent load-shifting programs, especially if those programs are non-dispatchable. However, until such time as a future Commission decision determines a specific cost-effectiveness method for load-shifting programs, LSEs should use these protocols. If an LSE determines that modifications to these protocols should be made to accommodate a load-shifting program, then those modifications must be clearly described and approved in writing by the Commission.

These protocols are not designed to measure “pilot” programs, which are done for experimental or research purposes, technical assistance, educational or marketing and outreach activities which promote DR or other energy-saving activities in general, although the cost of some of these programs will be considered when measuring cost-effectiveness.

Unless directed otherwise in a particular case, these protocols should be used for cost-effectiveness analysis of all DR programs, as defined above, when an LSE is seeking budget approval for a program. This includes programs proposed as part of a multi-year Demand Response application, proposed individually in an Application or Advice Letter, or as part of a proceeding that focuses on another matter, such as a General Rate Case. In general, if an LSE is requesting approval of a budget for a DR program with measureable load impacts, a cost-effectiveness analysis of that program is required in the proceeding in which the budget is being requested. LSEs are also required to file cost-effectiveness analysis for their DR portfolio, as discussed in Section 1.H.

For the purposes of this cost-effectiveness analysis, some DR programs should be divided into sub-programs, where each sub-program is analyzed separately. Whenever parts of a program have distinctly different characteristics that would lead them to have different costs or benefits, that program should be divided into sub-programs. For example, a program which has a day-ahead and day-of option should be considered to be two separate sub-programs, and a separate cost-effectiveness analysis should be provided for each one. In practical terms, this means that there should be a separate tab on the DR Cost-Effectiveness Report for each sub-program.

We recognize that there are a wide variety of DR programs with differing attributes. Therefore, flexibility in the application of these protocols may be necessary to fully reflect the attributes of some DR programs. The valuation of DR programs may also be affected by future Commission decisions on short-term and long-term resource adequacy, long-term procurement, avoided costs, Smart Grid or other issues, by actual program design and operations, and by emerging markets for DR that are being developed by the California Independent System Operator (CAISO). It

may become necessary for the Commission or an individual LSE to update or modify methods or values in future cost-effectiveness evaluations, if doing so is necessary to provide accurate results. However, if an LSE believes any such updates or modifications are required, they must be clearly described and justified to all parties, and approved in writing by the Commission.

There are a number of different methods that could be used to determine the cost-effectiveness of demand response. Two possible methods are the business case approach, as the IOUs used in the business cases included in their Advanced Metering Infrastructure (AMI) applications, and the Integrated Resource Planning (IRP) approach. Both of these approaches could be workable for programs that have a large decremental effect on demand, but these approaches are generally not “sensitive” enough to properly measure the costs and benefits of specific demand response programs, which often have relatively small impacts. To evaluate programs with small impacts more precisely, these protocols employ a marginal cost approach. The marginal cost approach directly compares the DR resource to traditional generation from a long-term resource planning perspective. These protocols measure the cost-effectiveness of DR programs by comparing their costs and benefits to the costs and benefits of a combustion turbine (CT), which is the most common supply-side resource used to meet peak energy demand. The time period for the cost-effectiveness evaluation should be limited to the length of the program cycle (usually three years), unless it is demonstrated that a longer period of analysis is necessary. Capital investments that are expected to provide benefits beyond the current program cycle may be amortized over an appropriate period, as discussed in Section 3.E.

The methods described in these protocols should be used for *ex ante* evaluation of DR cost-effectiveness. *Ex post* evaluations of the cost-effectiveness of DR activities would not be an appropriate way to determine program approval, because one important function of demand response is to provide “insurance” against relatively low probability and/or intermittent events that can have severe consequences when they occur. If those events did not occur during a given time period, it does not necessarily mean that those demand response programs were less valuable or less cost effective *ex post*. An analogy which is often used to describe this value is to compare demand response with a homeowner’s fire insurance policy, since fire insurance still provides value to the homeowner even if there is never a fire in their house. However, the expense of this insurance does need to be comparable to the value provided – to carry the analogy further, if the homeowner is paying more for fire insurance than was paid for the house itself, or is unwilling to file a claim even if a fire occurs, it is time to examine whether the insurance policy is appropriate. In addition, we recognize that while the insurance provided by demand response is valuable, it has become a less significant aspect of demand response as new technologies and markets enable DR to be used to respond to a greater variety of system needs.

Therefore, we recognize that *ex post* analysis is useful for informing assumptions or forecasts needed for *ex ante* analysis, and to better understand the relative need for and value of particular Demand Response programs. *Ex ante* cost-effectiveness evaluations should be adjusted for actual *ex post* experience from previous demand response program budgeting cycles or filings. Thus, each cost-effectiveness test should use, to the maximum degree possible, actual program experience from previous years to ensure the new forecasts are consistent with actual experience. Hence, we will require that LSEs perform, at least once during each budget cycle, an *ex post* cost-effectiveness analysis of each DR program.

### **Section 1.B: Methods Used to Estimate Costs and Benefits**

Previous to the adoption of the 2010 Protocols, each IOU used its own inputs and models for calculating DR cost-effectiveness. The use of separate models and data, some of which are proprietary, produced results that varied significantly, in particular for the certain aspects of the avoided cost calculations, such as gross margins and residual capacity value. Some variation would be expected due to the different characteristics of each utility system. However, as a significant portion of the IOUs' analysis and data inputs used were either held as proprietary or were not very transparent, it was extremely difficult to determine to what degree the variations reflect actual differences in the IOU service territories or were due to different underlying assumptions, input data, modeling approaches or other factors.

To address this confusion, these protocols require that all LSEs use the same public and transparent cost-effectiveness model provided by the Commission. This approach is consistent with that used for reporting energy efficiency and distributed generation cost-effectiveness. As in those proceedings, two models will be used, one to calculate avoided costs and one to report program cost-effectiveness results.

The avoided cost model used for DR cost-effectiveness calculations was derived from the Distributed Generation (DG) Cost-Effectiveness framework adopted by the Commission in D. 09-08-026, which specifies the use of a marginal avoided cost-based approach to distributed resource valuation. The avoided costs are calculated using the Avoided Cost Calculator, a spreadsheet tool developed by Energy and Environmental Economics (E3) as part of the DG Cost-Effectiveness framework. The Avoided Cost Calculator is now used to estimate the avoided costs of all demand-side programs. In analyzing the cost-effectiveness of resources, LSEs shall use the most recent version of the Avoided Cost Calculator that conforms with the requirements of these protocols. This may require modifications to an existing version of the calculator. More information about the calculation of avoided costs is found below in Section 3.B.

In 2009, Commission staff provided the IOUs with an Excel spreadsheet template to facilitate consistent reporting of DR program cost-effectiveness results. An updated version of that spreadsheet will be used by LSEs to report DR program cost-effectiveness and will be considered part of these protocols. This DR Cost-Effectiveness Report (previously called the DR Reporting Template) will limit the number of inputs by the LSEs to a few key fields. All the calculations and formulas pertaining to avoided costs and cost-effectiveness will be contained within the DR Cost-Effectiveness Report. This will enhance both the transparency and consistency of those calculations. The DR Cost-Effectiveness Report will include a sensitivity analysis, showing how the benefit-cost ratios vary with changes in several key inputs. In addition to the spreadsheet portion of the DR Cost-Effectiveness Report, LSEs will be required to provide workpapers which include a written explanation where required by these 2014 protocols. The workpapers should provide detailed explanations of all assumptions and calculations, including an explanation of how those adjustment factors not calculated in the DR Cost-Effectiveness Report were determined for each program. In addition, the workpapers must include an explanation of all other assumptions or calculations that were made to determine any of the cost and benefit inputs whose derivation is not clear.

LSEs must submit their cost effectiveness analyses by filling out the DR Cost-Effectiveness Report spreadsheet and accompanying workpapers. In the spreadsheet, a separate tab should be created for each DR program, or subprogram when necessary, and then the resulting DR Cost-Effectiveness Report spreadsheet and workpapers should be submitted with the Application or Advice Letter seeking program approval or modification. The spreadsheet file that is submitted should be named in a way that makes it obvious what it contains (e.g., “SCE DR Report.xls”). LSEs can use any part of the spreadsheet or workpapers in any section of their applications, but the spreadsheet and workpapers themselves must also be filed as part of the application.

The DR Cost-Effectiveness Report is meant to be a tool that anyone can use. All parties are encouraged to make use of it for their own analyses. For example, any party (including any LSE) can substitute a different quantity for any input and generate alternate cost-effectiveness results. These alternate results may help all parties and the Commission to understand how different conditions, assumptions, or future events might affect the cost-effectiveness of DR programs.

The ~~template~~ report will promote the transparency of the DR evaluation process and allow for more efficient review of proposed DR programs by the Commission and stakeholders. The ~~templates~~ report will be preloaded with the following information:

1. Avoided Generation Capacity Costs
2. Avoided Energy Costs
3. Avoided Transmission and Distribution Costs for PG&E, SDG&E, and SCE
4. Avoided Environmental Costs for Greenhouse Gases (GHG)
5. Line Losses for PG&E, SDG&E, and SCE
6. Weighted Average Cost of Capital (WACC) for PG&E, SDG&E, and SCE

The LSE will specify the following quantitative information relevant to the evaluation of each program, following the procedures outlined in these protocols:

1. Load Impacts, in MW
2. Expected call hours of the program (used to determine eEnergy sSavings), ~~based on expected call hours of the program~~
3. Administrative Costs
4. Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)
5. Capital Costs and Amortization Period, both to the LSE and to the Participant (should be specified for each investment)
6. Revenues from participation in CAISO Markets (such as ancillary services or proxy demand resource)
  - CAISO Markets Entered
  - Average megawatts (MWs) and hours bid into those
  - Average market price received
7. Bill reductions and increases
8. Incentives paid
9. Increased supply costs

10. Revenue gain/loss from changes in sales (usually assumed to be the same as bill reductions and increases)
11. Adjustment Factors (if not using default values)
  - data need to calculate Availability (A Factor)
  - Notification Time (B Factor)
  - Trigger (C Factor)
  - Distribution (D Factor)
  - Energy Price (E Factor)
  - Flexibility (F Factor)
  - Geographical/local avoided generation capacity (G Factor)

The LSE may also add the following optional inputs:

1. Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
2. Utility non-energy benefits, such as fewer customer calls and improved customer relations.
3. Participant non-energy benefits, such as improved ability to manage energy use and “feeling green.”
4. Market benefits, such as market power mitigation and market transformation benefits

All estimations of the MW impacts of demand response resources should be based on the Load Impact Protocols.<sup>7</sup> The load impacts used to determine cost-effectiveness of a DR program should be the same as the Net Qualifying Capacity (NQC) of that program used to fulfill the LSE’s Resource Adequacy (RA) requirement, as determined by the RA counting rules and requirements in D.10-06-036,<sup>8</sup> or any subsequent RA decision, when those numbers are available. If the NQC for a particular program is not available for some or all years, LSEs can either use the program’s forecast LI, as defined below, or derive the program’s likely NQC using the same methods as were used to determine the program’s NQC for any year in which an NQC is available. Monthly load impacts should be used to calculate DR costs and benefits to account for varying enrollment levels and avoided cost values over the course of the year. The Avoided Cost Calculator will allocate avoided cost components to individual hours to provide total or average monthly benefit values which can then be used with the monthly load impacts for benefit calculations.

The current practice for determining the NQC is to start with the load impact reported for that program in the most recent annual April Load Impact Compliance Filing. If the load impacts for a particular program were not estimated in the most recent Load Impact Compliance Filing, they should be estimated using the methods outlined in the Load Impact Protocols. The specific data which are currently used are the 1-in-2 weather year, 50<sup>th</sup> percentile *ex ante* hourly impacts, adjusted for dual participation, averaged over the RA measurement hours for DR<sup>9</sup> of the peak

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<sup>7</sup> Decision 08-04-050 Adopting Protocols for Estimating Demand Response Load Impacts, April 24, 2008.  
[http://docs.cpuc.ca.gov/PUBLISHED/FINAL\\_DECISION/81972.htm](http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm)

<sup>8</sup> As shown in Appendix B, p.19.

<sup>9</sup> The measurement hours for January – March, November and December are 4:00 – 9:00 p.m.; for all other months the hours 1:00 – 6:00 p.m.

day for each month, then adjusted, as determined by Commission staff, to calculate each program's NQC. For the purpose of the sensitivity analysis, the 10<sup>th</sup> and 90<sup>th</sup> percentile values should be used as the low and high values. It is possible that all or part of this current process of calculating NQC will change in the future. The LSEs are required to use load impacts that are consistent with the RA procedures for determining the NQC that are current at the time of any cost-effectiveness filing.

All load impacts used should reflect Commission staff's adjustments, if applicable, to the underlying input assumptions used in the Load Impact Compliance Filing to calculate the NQC in the most recent RA process. These adjustments are usually made to the load impact forecasts in the IOUs' annual April Load Impact Compliance Filings to reflect factors such as past program performance or updated enrollment information, and are generally made only for one year. Hence, they might not include the years for which the cost-effectiveness analysis is being calculated. In that case, LSEs should attempt to make a similar adjustment to the estimated load impacts reported in the annual compliance filing as is done to determine the NQC for each program. This procedure should also be followed to determine the low and high values for the sensitivity analysis. However, as stated above, if the LSE cannot determine the NQC for some or all years of the program, it may use 1-in-2 weather year, 50<sup>th</sup> percentile *ex ante* hourly impacts, adjusted for dual participation, averaged over the RA measurement hours for DR of the peak day for each month, and the 10<sup>th</sup> and 90<sup>th</sup> percentile values for the sensitivity analysis.

LSEs will be permitted to adjust the energy, generation capacity and T&D capacity values taken from the Avoided Cost Calculator as appropriate to apply those values to individual DR programs with different characteristics. Utilities will input each of ~~five possible~~ the adjustment factors, or the data needed to calculate them, that will be applied to the avoided costs, unless using the default values of the factors. Each of the ~~five~~ factors listed above will be input as a percentage adjustment to the relevant avoided cost values. More information on how to calculate these factors can be found in Section 3.B.

Program reporting will be limited to the length of time specified in the proceeding in which the cost-effectiveness analysis is being filed, which is generally three years. LSEs may amortize capital costs over a longer period. However, since DR programs experience some level of customer turnover and technology changes rapidly, LSEs will be expected to document that installed capital equipment will actually be "used and useful" in providing load reductions over the assumed useful life.

LSEs must also forecast the expected number of hours each dispatchable DR program will be called and, ~~based on the program's load impacts, input the expected energy (MWh) savings of the program~~ input that information in the report. LSEs should base their forecast of expected call hours on program history (when available) and explain how the forecast was made.

With the inputs described above, the DR Cost-Effectiveness Report will calculate the costs and benefits of each DR program. The DR Cost-Effectiveness Report will use each IOU's most recent after-tax Weighted Average Cost of Capital (WACC) to calculate the Net Present Value (NPV) of program costs and benefits and to amortize capital expenditures over their expected useful lifetimes. The DR Cost-Effectiveness Report will calculate the total costs and benefits,

based on the Standard Practice Manual tests, for each program, following the methods specified in these protocols. The DR Cost-Effectiveness Report will also calculate the \$/kW-yr costs of the kW reductions provided by each program and perform a sensitivity analysis of key inputs, as discussed in Section 1.F below.

### **Section 1.C: Confidentiality**

The DR cost-effectiveness methods presented in these protocols should promote transparency by using clear and publicly available data and data sources. While accuracy and precision are critical elements of any measurement, transparency and clarity are also critical components of establishing results in which all parties can have confidence. Therefore, these protocols discourage the use of confidential or proprietary data unless a clear and compelling case can be made that there are insufficient public data to perform a specific calculation. LSEs may use confidential or proprietary data and models only with written permission from the Commission. This permission must be obtained *before* an LSE files an application or advice letter which includes the analysis. In addition, if permission is granted and an analysis that depends on the confidential data is done, it will be accompanied by a separate analysis using publicly available data. If confidential or proprietary data and analyses are used for any part of a utility's cost-effectiveness analysis, those data are entitled to the confidentiality protections recognized in Commission decisions.<sup>10</sup>

### **Section 1.D: Relationship to the Standard Practice Manual**

These cost-effectiveness protocols use the tests described in the California Standard Practice Manual (SPM),<sup>11</sup> which was developed to measure the cost-effectiveness of energy efficiency programs, to provide the basis for comparing the costs and benefits of demand response. The SPM contains four different tests, each of which measures cost-effectiveness from a different perspective. These tests are not intended to be used individually or in isolation. Rather, the tests are to be compared to each other, and tradeoffs between the tests considered. These protocols require that *all* the SPM tests, as defined below, be used to describe the cost-effectiveness of both individual DR programs and each LSE's DR portfolio.

The relative weight given to any SPM test in determining program approval will be determined within DR budget proceedings, or other Application or Advice Letter proceedings in which an LSE is requesting approval of demand response programs. Nevertheless, we expect that the TRC and PAC tests will continue to be used as the primary tests associated with program and portfolio approval. As noted in the SPM, the Participant Test is useful for better understanding the desirability of a program, from the perspective of potential participants, and is useful for program design purposes, especially in setting incentive levels. The SPM also notes that the "Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects." The RIM test reflects only the potential impact on rates, and the SPM notes that the "(r)esults of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are

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<sup>10</sup> See Section 454.5(g) of the California Public Utilities Code and D.06-06-066.

<sup>11</sup> [http://www.energy.ca.gov/greenbuilding/documents/background/07-J\\_CPUC\\_STANDARD\\_PRACTICE\\_MANUAL.PDF](http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF)

difficult to quantify with certainty.” In addition, the possibility of rate increases may be one of only many things for the Commission to consider when determining whether to invest ratepayer funds in programs which are designed to support policy goals such as GHG mitigation and reduction of pollutants.

The results of each SPM test are based on the net present value of program costs and benefits over the lifecycle of those impacts. Because the SPM is the starting point for the cost-effectiveness methods in these protocols, modifications have been made to selected elements of the SPM tests to better adapt them for use with DR.

### **Section 1.E: Relationship to the Planning Reserve Margin and Resource Adequacy**

DR programs avoid the need for generation capacity since they are designed to reduce customer usage during periods when supply-side resources might be unavailable, constrained or expensive, particularly during peak summer afternoon hours. The amount of total capacity that the Commission requires each LSE to maintain is determined by the Resource Adequacy (RA) requirements established by the Commission. The determination of the value provided by and the cost-effectiveness of any demand response resource may be affected by any changes in the rules used to calculate RA values, as determined in the current RA proceeding (R.11-10-023), or its successor.

### **Section 1.F: Sensitivity Analysis**

Many of the costs and benefits of Demand Response (and other) programs are based on uncertain inputs or have considerable variation among participants, LSEs and others, making them difficult or prohibitively expensive to quantify. Some costs and benefits are presented as precise quantities, but are actually *estimates* because they are dependent on assumptions and estimated inputs. Costs and benefits which cannot be easily quantified are often approximated, and if they cannot be approximated they have often been ignored in previous cost effectiveness analyses. This approach, while pragmatic, does not allow for an assessment of the true costs and benefits of these programs. In that light, the DR Cost-Effectiveness Report will perform additional types of analyses than have been done in past proceedings.

These protocols require that sensitivity analysis be performed on key variables, defined as those costs and benefits (or components thereof) which are (a) substantially uncertain and (b) likely to have a significant impact on SPM test calculations. The sensitivity analyses will be made using only the TRC test, to make it feasible for both the parties in any DR proceeding and the Commission to complete and analyze the cost-effectiveness filings in a timely manner. The variability in the TRC values calculated in the sensitivity analysis should be sufficient to demonstrate the potential variability in the other SPM tests.

A sensitivity analysis is required for each key variable. Commission staff will determine the exact range of the sensitivity analysis during the course of any particular DR proceeding. The key variables are:

1. Participant Costs
2. Avoided Capacity Cost
3. T&D Capacity Costs

4. Capital Amortization Period
5. Load Impact
6. A Factor Adjustment to the Avoided Capacity Costs

**Participant Costs**, as discussed in Section 3.M, are equal to the sum of Transaction Costs and the Value of Service Lost. Because those two quantities are extremely difficult to quantify, other costs are used as a proxy. In the past, Participant Costs have been presumed to be equal to Participant Benefits, which are defined as the cost of customer incentives and bill reductions, minus any customer capital costs. However, this is clearly inaccurate, since it is more likely that customers participate in programs because the benefits **exceed** the costs. Hence, a more accurate assumption is that Participant Benefits are the maximum value for Participant Costs.<sup>12</sup> Hence, the sensitivity analysis will use the quantity Incentive Costs + Bill Reductions – Capital Costs to Participant as a **high** value, rather than as the base case value, for most DR programs. This is explained further in Section 3.M.

For **Generation Capacity Value**, the value calculated by the Avoided Cost Calculator will be considered the base case value. This value is based on the long-term Avoided Generation Capacity Costs, which are determined from the Combustion Turbine simulation. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff. The percentage currently used is 30%.

For **T&D Capacity Value**, the values calculated by the Avoided Cost Calculator will be considered the base case values. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff. Separate values are provided for transmission and distribution, for each of the IOUs (PG&E, SCE and SDG&E). Other LSEs may input the appropriate values for their service territories.

Each LSE should input the **Capital Amortization Period** for each long-term investment. The low value of each long-term investment for each year of the program cycle will be the annual levelized value of that investment over its expected useful lifetime. The high value will be determined by setting the Capital Amortization Period equal to the length of the program cycle (usually three years) for which the cost-effectiveness analysis is being performed.. The base value will be the halfway point between the calculated low and high values.

Commission staff will determine default values for **Capital Amortization Period** for different types of investments, and will use those values if none is provided by the LSE, as explained in Section 3.E. [Commission staff](#)

The exact **Load Impacts** which should be used for each program are defined above in Section 1B. A sensitivity analysis will be performed using the 10<sup>th</sup> and 90<sup>th</sup> percentile values as low and high values. Note that although this was required by the 2010 Protocols, the DR Reporting

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<sup>12</sup> This calculation is complicated by the fact that there are other pParticipant bBenefits which are difficult to quantify--- the Non-energy and Non-monetary benefits discussed in Section 3.JK. These benefits are not considered in the simple analysis above. However, parties are encouraged to propose a different proxy value for Participant Costs, or alternate methods of calculating Participant Costs, should they have evidence that an alternative method would improve the cost-effectiveness analysis.

Template inadvertently applied the same method (30% higher and lower than the base value) to the sensitivity analysis of the load impacts as was used for most of the other variables. This will be corrected in the DR Cost-Effectiveness Report.

Sensitivity analysis of the adjustment factors is required only for the **A factor** (discussed in Section 3.B., below). A factors will be determined by the new model being adopted, as discussed in Section 3.B. below, which will be integrated into the DR Cost-Effectiveness Report. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff.

### **Section 1.G: Qualitative Analysis**

As discussed in Section 1.B, LSEs may choose to, but are not required to, add the following optional inputs in the DR Cost-Effectiveness Report:

1. Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
2. Utility non-energy benefits, such as fewer customer calls and improved customer relations.
3. Participant non-energy benefits, such as improved ability to manage energy use and “feeling green.”
4. Market benefits, such as market power mitigation and market transformation benefits

LSEs should include these inputs if and when it is possible to estimate quantitative values for any one of them for a specific DR program. Where it is not possible to approximate an optional input, qualitative analysis of these costs and benefits, especially when they are relevant to a specific DR program, should be provided by the LSE or by any party commenting on the analysis. Qualitative analysis is a descriptive analysis of the possible magnitude and impact of that cost or benefit. It may also include a description of any variation based on location, customer class, or any other significant factor. In addition, the qualitative analysis may reference relevant research, or propose future research.

The purpose of this qualitative analysis is not to make vague speculations about the nature of those inputs, but to better understand the impact of DR on the electric grid, and in particular to compare DR programs to each other in those instances in which a particular DR program clearly has a different amount of a particular cost or benefit, even if that amount cannot be precisely (or even imprecisely) quantified. An example would be two programs that target different customer classes, but are otherwise the same. In this case, the customer costs and benefits will mostly be difficult to quantify, but could more easily be discussed qualitatively, allowing all parties to better understand the relative merits of the two programs.

An important goal of the qualitative analysis is to establish an ongoing dialog among DR stakeholders that can lead to better understanding of the complete range of benefits and costs of DR. For this reason, we require that LSEs put some thought into their analyses of each type of optional benefit. LSEs may argue that they believe these benefits do not exist, but no matter

what belief an LSE, or other party, advocates we expect this analysis to be backed up with research, data, and thoughtful analysis.

For each of the optional inputs listed in above, and for each DR program, LSEs should determine their approach. If an LSE chooses to estimate a value for any of these inputs, an explanation of how the value was derived should be included in the workpapers. If a value cannot be estimated, the LSE shall provide in its workpapers a qualitative analysis which discusses the extent to which their DR program(s) provide non-energy or market benefits. We recognize that this type of analysis is a departure from the traditional cost-effectiveness analysis that IOUs are accustomed to. Nevertheless, we expect all LSEs to comply with this requirement. . Other parties are encouraged to provide relevant information about any of the optional inputs.

The 2010 Protocols required the above qualitative analysis. However, this was not provided by the IOUs in their 2012-14 Applications. As a result, and as noted in D.12-04-045, the IOUs were out of compliance with these protocols. Hence, this analysis will be required as part of the workpapers associated with the DR Cost-Effectiveness Report.

### **Section 1.H: Portfolio Analysis**

In addition to providing cost-effectiveness analysis of each DR program, LSEs will also provide cost-effectiveness analysis of their entire DR portfolio. This should be done for each SPM test by aggregating all DR programs, and adding additional relevant costs and benefits, while correcting for any possible double-counting due to dual participation or other factors. This portfolio analysis shall include any marketing, IT, administrative, equipment or other costs associated with the LSE's portfolio of DR programs. It should **also** include costs associated with broader activities, including any DR-related activities such as customer audits; evaluation, measurement and verification; and marketing, education and outreach, or any other activity which supports or promotes DR in general rather than any one specific DR program.

Note that the portfolio analysis must include an analysis of *all* Demand Response activities, programs, and costs, whether or not the LSE is requesting budget approval for each of individual programs included in the portfolio analysis. For example, if an LSE received approval in a past CPUC proceeding for an ongoing program which does not require re-approval in the current application (e.g., a program which is done through a long-term contract), a cost-effectiveness analysis for that ongoing program must be included as part of the portfolio analysis. As another example, the portfolio analysis must include all costs related to DR that were approved in the LSE's most recent GRC, and any other relevant proceeding. LSEs should include, as part of their workpapers, a list of *specific budget items* from their latest GRC and all other proceedings in which approval of any costs related to DR was included.

The only type of costs which can be excluded from the portfolio cost-effectiveness analysis are the costs associated with "pilot" programs, which are done for experimental or research purposes, as the benefits of these programs are generally substantial, but usually impossible to forecast. However, if an LSE is able to quantify both the costs and benefits of any particular pilot program, it must include that program's costs and benefits in its portfolio analysis. If, as will be the case for most pilots, it is not possible to estimate the benefits of the pilot project, the LSE should clearly explain this as part of the description of the pilot program.

The portfolio cost-effectiveness analysis is only one of the analyses which should be included in an LSE's DR budget application. In any individual DR proceeding, the Commission will base the approval of one or more DR programs on all information provided in an LSE's application. The Commission may approve DR programs, budgets, or activities individually, or the Commission may approve an LSE's entire portfolio, with or without modifications. The inclusion of the portfolio cost-effectiveness requirement should not be construed as an indication that the Commission intends to use portfolio cost-effectiveness, rather than program cost-effectiveness, as the basis for budget approval. These 2014 Protocols are designed to simply establish the requirements for cost-effectiveness analysis, not the policies by which program approval will be determined.

### **Section 1.I: Dual Participation**

DR programs which allow dual participation, in which participants can enroll in more than one DR program, require special rules to accurately determine their cost-effectiveness. The 2010 Protocols required that the load impacts of any DR program that allows dual participation follow the rules described in D.09-08-027, Section 18.4. Those rules require that the load impacts of dually-participating customers be attributed to only one program so as to avoid double-counting. Dual participation rules limit participants to enrollment in one capacity program and one energy program<sup>13</sup>, and require that the load impacts of dually-participating customers be attributed to the capacity program.

During the 2012-14 utility DR portfolio proceeding, it became evident that attributing the load impacts of dually-participating customers only to the capacity programs was resulting in underestimates of the cost-effectiveness of the energy programs, since the cost-effectiveness analysis of the energy programs included all of the costs of administering them but only part of the benefits. During a subsequent demand response cost-effectiveness workshop<sup>14</sup>, there was general consensus that this practice should change. However, there are a number of approaches, and it is not clear which will best provide the information needed to determine the cost-effectiveness of these programs. The options include:

- Requiring an additional analysis of both the capacity and the energy program combined.
- Including the dually participating customers in the separate analysis of each program, while taking care not to double-count when calculating the DR portfolio cost-effectiveness.
- Requiring an additional analysis of only the dually-enrolled customers in both the capacity and energy programs.

Determining the best approach will depend on which is the most important among the following goals: determining the cost-effectiveness of dual participation itself, of the individual programs, or of the combined programs. Requiring all three of these analyses could place an unnecessary burden on LSEs and Commission staff to provide and analyze this additional information.

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<sup>13</sup> A capacity program pays capacity incentives, in \$/kW, to participants in return for the participant's willingness to reduce to a pre-set level of demand whenever needed. An energy program pays incentives in \$/kWh for the energy reductions that a customer provides during DR events.

<sup>14</sup> held on October 19, 2012

More stakeholder input is needed on this issue before a final determination can be made.

## **SECTION 2: USING THE STANDARD PRACTICE MANUAL TESTS TO DETERMINE DR COST-EFFECTIVENESS**

This section describes the modified SPM tests that shall be used to determine DR cost-effectiveness. These four test each reflect a different perspective. While various Commission proceedings have expressed a preference for one or the other of these four tests, these protocols do **not** do so. Each of these perspectives are significant, although the significance of each may vary for different DR programs or proceedings. The output of each test is based on the net present value of the costs and benefits, discounted over the lifetime of the relevant DR resource. Hence, the costs and benefits listed below are not simply added together to produce the SPM outputs. Rather, the costs and benefits should be calculated using the DR Cost-Effectiveness Report and Avoided Cost Calculator, using the given discount rate and the net present values, by filling out the appropriate cells of the spreadsheets. The paragraphs below provide generalized and simplified descriptions of those calculations.

### **Section 2.A: Total Resource Cost (TRC) Test**

The TRC test calculates the costs and benefits to “society” of a demand-side resource. For the purposes of these protocols, “society” is considered to be each LSE and its customers.<sup>15</sup>

In the SPM, TRC benefits are limited to the LSE’s avoided costs of supplying electricity and tax credits (if available). For DR programs, additional benefits include any revenue the program may earn in exchange for CAISO market participation (such as for providing ancillary services). In addition, to make the TRC test better reflect the true costs and benefits of DR to ratepayers, these additional benefits should be considered:

- Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, or health benefits.
- Utility non-energy benefits, such as fewer customer calls or improved customer relations.
- Market benefits, such as market power mitigation or market transformation benefits

From the perspective of the TRC, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Participant costs (capital costs to participant + value of service lost + transaction costs)
- Increased supply costs, if any

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report. For those costs and benefits which cannot be quantified, LSEs or other parties should provide a qualitative analysis of particular cost or benefit, as discussed in Section 1F.

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<sup>15</sup> This assumes that each LSE is capturing any possible “spillover” impacts that may occur outside its service territory.

### **Section 2.B: Program Administrators Cost (PAC) Test**

The PAC test measures cost-effectiveness from the perspective of the LSE or other entity administering the Demand Response program. The benefits are the:

- Avoided costs of supplying electricity
- Revenue the program may earn in exchange for CAISO market participation
- Utility non-energy benefits
- Market benefits

From the perspective of the PAC, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Incentives paid
- Increased supply costs, if any

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report.

### **Section 2.C: Ratepayer Impact Measure (RIM) Test**

The RIM test, also called the non-participants test, measures the costs and benefits of a demand response program from the perspective of its impact on rates. The benefits considered in this test are:

- Avoided costs of supplying electricity
- Revenue from participation in CAISO Markets
- Revenue gain from increased sales, if any
- Market benefits

From the perspective of the RIM test, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Incentives paid
- Increased supply costs
- Revenue loss from reduced sales

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report.

### **Section 2.D: Participant Test**

The Participant Test measures the cost-effectiveness of a Demand Response program from the perspective of a participant. For the purposes of these protocols, a participant is considered to be a ratepayer who is an end-user of electricity and participating in a DR program. From this perspective, the benefits of a DR program are:

- Bill reductions
- Incentives received
- Participant non-energy benefits
- Tax credits, if available

From the participant's perspective, the costs are:

- Bill Increases
- Capital, O&M, removal and any other costs associated with DR equipment installed
- Value of service lost (lost productivity and comfort costs)
- Transaction costs (opportunity costs associated with education, equipment installation, program application, event response management, energy audits, etc.)

Each of these costs and benefits is discussed further below. Some of these costs and benefits are difficult, if not impossible, to calculate. However, it is reasonable to assume that a customer would not voluntarily participate in a DR program if the benefits did not exceed the costs. Hence, for the purpose of DR programs in which customers have the option to enroll or not (generally referred to as “voluntary” programs), it can be assumed that the costs are less than the benefits, since a rational electricity end-user would not otherwise participate in the program. Therefore, when presenting cost-effectiveness analysis of voluntary DR programs, the LSE should simply state that the benefit/cost ratio for the Participant Test is greater than 1. Note that programs that are described as “default opt-out<sup>16</sup>” programs, for the purposes of this analysis, are considered to be voluntary programs.

For default programs which do not have an opt-out provision (i.e., programs in which all customers in a specific class are considered participants and opting out is not possible), a more detailed analysis must be provided. LSEs should provide an estimate for each cost and benefit which can be calculated, and any information available for other costs and benefits. However, it is understood that many, if not most, of the costs and benefits listed here are extremely difficult to quantify.

Nevertheless, there is value in trying to better understand these participant costs and benefits. The deployment of Smart Meters allows all utility customers the opportunity to better manage their electricity usage, including participation in demand response programs. However, making use of that opportunity will require an in-depth understanding of energy management. A better understanding of DR costs and benefits from a customer's perspective will better enable all parties to increase customer involvement in DR activities. While the participant test is not generally used to determine program approval, it can offer valuable information that can be used to improve program design and help predict customer enrollment, as discussed above. It is particularly important for LSEs to provide the best estimate possible of Participant Test cost-effectiveness for new programs.

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<sup>16</sup> A default opt-out program is one in which all customers in a certain class are placed in the program as a default, but all customers have the option to opt out of participation by informing the utility during a specified time period. These programs are sometimes referred to simply as “default” programs.

### SECTION 3: COSTS AND BENEFITS OF DEMAND RESPONSE

Table 1

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
CAISO Market Participation Revenue	BENEFIT	BENEFIT	BENEFIT	
Capital costs to LSE	COST	COST	COST	
Capital costs to participant	COST			COST
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy social benefits	BENEFIT			
Non-energy utility benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy participant benefits				BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax Credits	BENEFIT			BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

*Shaded rows indicate those costs and benefits which are not included in the SPM but have been added to these Demand Response protocols.*

#### **Section 3.A: Administrative Costs**

Administrative costs of a DR program are considered to be its operations and maintenance costs, program operational costs, IT costs, DR system operation and communication costs, the marketing and outreach costs associated with the program, evaluation, measurement, verification and reporting costs. LSEs are expected to provide budgets which detail these costs for each proposed DR program.

DR program administrative costs must include all costs that are caused by or specific to the program. All activities that are specific to a particular DR program, such as program design, development, operations, management, marketing, sales, IT infrastructure, evaluation, measurement, verification and reporting shall be included in the administrative costs of that program, even if it is budgeted separately or approved in a different proceeding than the DR program. This includes *all* costs that an LSE incurs because of the existence of DR. For example, if an LSE purchases hardware or software to upgrade their IT infrastructure, that portion of the investment that is necessitated by the existence of DR programs should be considered a cost of DR. LSEs must examine how the cost would have differed if DR programs did not exist. If that cost could not have been incurred if DR did not exist, then the entire cost must be included in the cost-effectiveness analysis. If that cost could have been lower if DR did not exist, then the difference between the lower cost and the actual cost must be included in the cost-effectiveness analysis.

When a program cost is budgeted separately (e.g., an IT budget which encompasses several programs), or when a program cost is part of a budget which was approved in a past CPUC

proceeding, those costs must be included as administrative costs in the cost-effectiveness analysis of an LSE's DR portfolio. In addition, those costs must be allocated to each individual DR program in the cost-effectiveness analysis of that program. Each LSE must provide, as part of their workpapers, a complete list of these two categories of costs, and include an explanation of how each budget item is used to support which DR programs. Those costs should be allocated to individual programs using the following procedure:

1. Estimation of the impact on or relationship to particular programs: For some budget items, it is possible to estimate how much of that budget will be used for particular programs. For example, EM&V costs are usually budgeted separately from program administration costs. However, it should be possible for an LSE to estimate how much of their EM&V budgets will be used to provide evaluation of each program. This is the preferred method to use for allocation of these budgets.
2. Limitation of use: For each budget listed, LSEs must provide a list of DR programs for which that budget is relevant. For example, a marketing program that targets residential customers would be relevant to only residential DR programs. This list should include all DR programs in the LSE's portfolio, whether or not program approval is being sought in the application.
3. Allocation by total budget: If it is not possible to estimate the proportion of a budget which pertains to a particular DR program, as explained in #1 above, then that budget should be allocated to each DR program that it pertains to, based on the list discussed in #2 above. The allocation should be proportional, based on the total administrative and incentive costs of the program.

The following is an example of the type of calculations and workpaper details that should be provided by LSEs. LSEs should provide similar tables and explanations in their workpapers:

Fictitious Electric Company has four demand response programs:

- Ag DR: Agricultural Capacity Response program, for agricultural customers only
- C&I DR: Base Interruptible Capacity program, for commercial and industrial customers only
- Res CPP: Summer Peaker Saver, a peak pricing program for residential customers only
- Res AC: Summer Saver Cycling, an air conditioner cycling, direct load control program for residential customers only

Fictitious Electric Company has nine budget items in its application:

Table 2

<b>Budget Line</b>	<b>Description</b>	<b>Amount</b>
1	Ag DR administrative costs	\$100,000
2	C&I DR administrative costs	\$300,000
3	Res CPP administrative costs	\$250,000
4	Res AC administrative costs	\$125,000
5	Res AC incentive costs	\$1,000,000
6	Evaluation, Measurement & Verification (EM&V)	\$200,000
7	Marketing, Education & Outreach (ME&O)	\$150,000
8	Customer Notifications (Notif)	\$85,000
	<b>TOTAL</b>	<b>\$2,210,000</b>

In addition, Fictitious Electric Company has identified the following costs, which were approved in their most recent General Rate Case, as being at least partially attributable to demand response programs:

Table 3

<b>Budget Line</b>	<b>Description</b>	<b>Amount</b>
GRC1	Ag DR incentive costs	\$1,000,000
GRC2	C&I DR incentive costs	\$1,000,000
GRC3	Software Upgrade 173B*	\$500,000
GRC4	Software Upgrade 84J	\$400,000
	<b>TOTAL</b>	<b>\$2,900,000</b>
	<b>Total DR attributable</b>	<b>\$2,600,000</b>

\*40% of the Software Upgrade 173B budget is attributable to DR

In its workpapers, Fictitious Electric Company provided a further breakdown of several budget lines:

#### Budget Line #6: EM&V

The \$200,000 in this budget line is estimated as follows:

- \$35,000 for load impact analysis of Ag DR
- \$35,000 for load impact analysis of C&I DR
- \$35,000 for load impact analysis of Res CPP
- \$35,000 for load impact analysis of Res AC
- \$30,000 for process evaluation of Res CPP
- \$30,000 for process evaluation of Res AV

#### Budget Line #7: ME&O

The \$150,000 in this budget line is estimated as follows:

- \$100,000 marketing campaign to support all demand response programs
- \$50,000 education campaign and materials for residential customers

#### Budget Line #GRC3: Software Upgrade 173B

Fictitious Electric Company estimates that 40% of the \$500,000, or \$200,000 of the cost of this software upgrade is attributable to demand response, and that this software is used for demand respond programs in general.

Fictitious Electric Company also notes that budget lines #8 (Customer Notifications) and #GRC4 (Software Upgrade 84J) are both entirely attributable to demand response, and used for demand respond programs in general.

Hence, Fictitious Electric Company provided the following analysis in their workpapers:

**Table 4: Budget Allocations, in thousands of dollars**

Program	Admin	Incent.	Admin + Incent.	% of total	Direct EM&V	ME&O	Notif.	Software 173B	Software 84J	TOTAL
Ag DR	100	1000	1100	29%	35	29	24.5	58	116	1362.5
C&I DR	300	1000	1300	34%	35	34	29	68	136	1602
Res CPP	250	0	250	7%	65	16	6	14	28	379
Res AC	125	1000	1125	30%	65	71	25.5	60	120	1466.5
TOTAL			3775	100%	200	150	85	200	400	4810

**Note:** ME&O costs = \$100,000 applied proportionally to all 4 DR programs, plus \$50,000 applied proportionally to the 2 residential DR programs. Notifications and software budgets are applied proportionally.

The sum of the application budget of \$2,210,000, and the portion of the GRC budget attributable to DR of \$2,600,000, is the total DR budget of \$4,810,000, and is allocated to Fictitious Electric Company's four DR programs as shown in the table above.

### **Section 3.B: Avoided Costs of Supplying Electricity**

The avoided costs of supplying electricity are the primary benefit of any demand side resource, and thus provides key information about the value of any proposed demand response resource, whether it is a load-modifying resource or a supply resource, which is bid into a CAISO market. Hence, the calculation of avoided costs will be used (1) to determine the primary benefit of load-modifying demand response resources, so as to compare those benefits to the costs of the resource and (2) to determine an avoided cost benchmark for supply resource demand response, which can be used to determine the reasonableness of a resource which is bid into a CAISO market.

The calculation of avoided costs differs depending on the specific characteristics of the particular resource. This is calculation is most accurate when avoided generation capacity costs, avoided energy costs, and avoided (deferred) transmission and distribution (T&D) costs are distinguished separately. DR programs can interact differently with each of these types of avoided costs, and the separation of the costs will allow such differences to be modeled in a straightforward manner. As discussed above, avoided costs will be calculated using the Avoided Cost Calculator, a spreadsheet tool developed by Energy and Environmental Economics (E3). The Avoided Cost Calculator uses a marginal cost-based approach to value each of the costs that the LSE avoided as a result of not having to deliver energy to the end-use customer.

In analyzing the cost-effectiveness of resources, LSEs shall use the most recent version of the Avoided Cost Calculator that conforms with the requirements of these protocols. This may require modifications to an existing version of the calculator.

The avoided costs considered include: energy purchases, generation capacity, line losses, transmission and distribution capacity, air pollution permits, offsets including CO<sub>2</sub>, ancillary services, and renewable energy purchases. The value of each of these elements is forecasted by hour and location for a 20-year period.

For demand response, the most significant avoided cost is the avoided cost of generation capacity. The forecast of generation capacity value made by the Avoided Cost Calculator includes both a short-run and a long-run component; the transition point between the two occurs in the resource balance year. The short-run value of capacity is based on the most recent publicly-available data on actual resource adequacy value. This value is currently much lower than the long-run value, which reflects the large surplus of capacity currently available on the CAISO system. Capacity value in the years between the date of the recent publicly-available data on actual resource adequacy value and the resource balance year is calculated by linear interpolation. Beginning in the resource balance year, the value of capacity is calculated based on the cost of a simple-cycle combustion turbine (CT), as that is the first year in which new capacity resources may be needed to meet the growth of peak loads and reliability requirements. The long-run capacity value is equal to the CT's annualized fixed cost less the net revenues it would earn through participation in the real-time energy and ancillary services markets—the residual capacity value.

The use of short- vs. long-run values for generation capacity has a substantial impact on the cost-effectiveness of DR. There are two schools of thought regarding whether the short- or long-run generation capacity value is the most appropriate for valuing DR. Several parties in various demand-side proceedings have argued that in a market with excess capacity, the lower, short-run value best expresses the actual capacity costs avoided and therefore the economic benefits realized by utility ratepayers and the region as a whole.

Others argue that relying on short-run values does not appropriately reflect the position of energy efficiency and demand response at the top of the loading order<sup>17</sup>. DR and EE, at the top of the Energy Action Plan loading order, should not be effectively penalized because a surplus of fossil generation exists during some periods.

In addition, it is important to consider that the long-term procurement plan (LTPP) proceeding determines whether and how much additional electric generation will be needed in the future. In that calculation, the amount of future peak-demand reducing EE, DR, and DG is estimated and deducted from the additional resources that would otherwise be authorized. This results in less authorization for the IOUs to procure additional capacity than would otherwise be authorized. While many other factors can come in to play that result in an excess (or a deficit) of supply resources, these intervening factors do not change the fact that future additions of demand-side resources are factored into this LTPP “net short” calculation. As they come on line in any given year, demand-side resources are replacing supply that otherwise would have been authorized five to ten years earlier in an LTPP proceeding.

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<sup>17</sup> California's energy policy, as stated in the Energy Action Plan ([http://www.energy.ca.gov/energy\\_action\\_plan/](http://www.energy.ca.gov/energy_action_plan/)), establishes a “loading order” which requires that demand be met first by cost-effective energy efficiency and demand reductions, next by renewables, and only then by traditional generation technologies.

Another argument for the use only of long-term values is that DR is analyzed only over the three-year budget cycle, and not over the lifetime of an equipment purchase, as most EE programs are. Therefore, use of both short- and long-term avoided capacity costs separated by a resource balance year has a very different impact on DR than on EE. Since the resource balance year is, and will be for the foreseeable future, at least three years away, it means that the cost-effectiveness of DR would be based only on short-term costs. This is in sharp contrast to EE measures, which are analyzed over a much longer period of time, since the lifetime of most energy-efficient equipment is at least five years,- necessitating the use of both long- and short-term values. Using only short-term values for DR would underestimate the real value of DR to the system. Ideally, this could be remedied by doing life-cycle analysis of DR, but that has proved to be impractical. In addition, some consistency in DR incentives is necessary to attract and retain DR participants.

Because Commission policy, as discussed at length in D.12-04-045<sup>18</sup>, is to follow the loading order and focus on the long-term development of clean energy resources, the long-run generation capacity value will continue to be used to determine the avoided generation capacity costs of DR programs,

The approach for incorporating ancillary services (AS) avoided costs will differ from the calculation used for EE and DG. The CAISO sets procurement targets for AS resources based on load forecasts. Demand side resources such as EE reduce overall loads and therefore reduce the quantity of AS that must be procured and paid for by the CAISO and ultimately by the LSEs. The CAISO has indicated that DR would not impact the procurement of AS in the Day Ahead market. Reduced load resulting from a DR event could reduce the quantity of AS procured in the Real-Time market. However, as 85 percent or more of AS is procured by the CAISO in the Day Ahead market, and AS costs are a relatively small percentage of the overall DR benefits, the benefit of reduced AS procurement need not be included in cost-effectiveness analyses of DR programs.

On the other hand, DR programs do have the potential to earn revenue in the AS and other CAISO markets. As discussed in Section 3.D below, such revenues earned by direct participation of DR programs in CAISO markets will be counted as a benefit. However, it is important to remember that this benefit is not part of the avoided costs of DR.

Because energy is a small portion of the overall benefits of DR programs, the avoided renewable energy purchases procurement costs calculated in the EE and DG Avoided Cost framework are negligible and will not be applied to DR cost-effectiveness.

The 2010 Protocols did include a value for avoided GHG costs, which is also based on avoided energy and is also quite small. Because of the relatively tiny amounts associated with avoided GHG costs for DR additional adjustments to the methods used to calculate this value will not be made at this time.

To characterize the hourly marginal avoided costs of serving load, the Avoided Cost Calculator incorporates publicly available data from the following sources: CAISO, the California Energy

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<sup>18</sup> see, especially, Section 7.1.4.2.1.

Commission (CEC), NYMEX, NOAA, the three major California IOUs, and Synapse Consulting. These inputs are not meant to be modified by IOUs, as their uniformity across analyses provides for an “apples-to-apples” comparison of the benefits of different distributed resources.

Table 5 summarizes each of the key data sources as well as a describing the specific data obtained from each.

Table 5. Key data sources used in the Avoided Cost Calculator

<b>Source</b>	<b>Description of Data</b>
CEC Cost of Generation Report	Costs and operating characteristics of a new combustion turbine and combined cycle power plants
CAISO OASIS	Hourly day-ahead and real-time LMPs; hourly system loads
NYMEX	Henry Hub forwards contract prices; basis differentials between Henry Hub and California gas hubs
California IOUs	Transmission & distribution deferral values; losses factors
Synapse Consulting	Forecast of carbon prices
NOAA	Hourly weather data throughout California

Table 6 shows the key outputs calculated within the Avoided Cost Calculator that are used to assess the cost-effectiveness of DR. A more detailed description of the method used to evaluate each of these components is found below.

Table 6. Main outputs of Avoided Cost Calculator used to evaluate DR resources.

<b>Output</b>	<b>Description</b>
Avoided Capacity Costs (Residual capacity value)	The annualized fixed cost of a new combustion turbine, less the net revenues (gross margins) that the CT could earn operating in the real-time energy and ancillary services markets
Avoided Energy Costs	Hourly values of energy in both the day-ahead and real-time markets (the appropriate value stream depends on the DR program characteristics)
Avoided GHG Costs	The value associated with a reduction in greenhouse gas emissions resulting from avoided thermal generation
Line losses	Additional costs resulting from line losses between the point of generation and the point of retail delivery

**1) Avoided Generation Capacity Costs:** The generation capacity costs avoided by a DR program will be based on the annual market value (\$/kW-year) of the residual capacity of a new combustion turbine (CT). Throughout this proceeding several alternate methods have been proposed for determining the adjusted CT cost. While each method has its laudatory features, we believe that transparency and simplicity are of paramount importance for these protocols. Therefore, the same method shall be used for all LSEs to determine this cost. The residual capacity value is calculated within the Avoided Cost Calculator using a method that is consistent with the California Independent System Operator (CAISO) Market Issues and Performance Annual Reports. Using cost and performance data from the CEC Cost of Generation Report, the calculator evaluates the net revenues that a new combustion turbine could expect to receive through operations in the real-time energy and other electricity markets. This net revenue is

subtracted from the combustion turbine's annualized fixed costs to determine the residual capacity value. Each of these components is described in further detail below. The dispatch of the CT is similar to the approach taken by the IOUs in earlier versions of these protocols, comparing the heat rate and the resulting variable operating costs against a forecast of energy prices to determine hours in which it is economic for the CT to operate.

The first component of the generation capacity value, the annualized fixed cost of a new combustion turbine, is calculated based on cost data from the CEC Cost of Generation Report and a pro-forma tool included in the Avoided Cost Calculator. The pro-forma tool amortizes the capital and fixed operations and maintenance costs associated with a new plant over its lifetime, yielding the annualized fixed costs of a new CT. These annualized fixed costs change in each year with the inflation of capital and O&M costs.

The second component of the residual capacity value, the CT's net margin from operations, will change each year with the evolution of the CAISO real-time market and the change in gas prices. The Avoided Cost Calculator calculates the expected net margin in each year based on the historical hourly shape of the real-time market adjusted by the average annual energy price in that year. In each hour, if the real-time market price exceeds the CT's cost of operation, the CT will dispatch, increasing its net margin by the difference between the market price and the cost of operation. The total net margin is calculated by tracking the CT's operations in the real-time market over each of the 8,760 hours of the year. As a flexible generator that can ramp up and down quickly, a CT can also earn revenues through participation in the ancillary services markets. In the Avoided Cost Calculator, this additional revenue is calculated as an upward adjustment to the gross revenues earned in the real-time market based on historic data gathered from CAISO's Annual Market Reports.

The Avoided Cost Calculator then allocates the residual capacity value across the 8760 hours of the year. This process is identical to the process used to determine the A factor, discussed below. The 2010 protocols suggested doing this by allocating the residual capacity value to the 250 hours of the year in which system loads are the highest. These are the hours in which marginal changes in consumption could result in avoided capacity costs. This type of capacity allocation method is a simplified proxy for relative loss of load expectation/probability (LOLE/LOLP) models, which were used previously to the 2010 Protocols to allocate generation capacity costs. This allocation is then used to create monthly generation capacity values, which are used with the monthly load impacts in the DR Cost-Effectiveness Report to calculate monthly avoided capacity costs. The 2010 Protocols also allowed LSEs to use their LOLE/LOLP models to determine alternate monthly capacity allocations for some or all DR programs, but required that the LSE provide both sets of calculations. Use of LOLE/LOLP models will no longer be permitted as an alternate calculation method.

During the 2012-14 DR portfolio proceeding, a simplistic method of allocating the residual capacity value to the 250 hours of the year in which system loads are the highest was used. This approach resulted in wildly varying allocations and A factor estimates for similar programs at different IOUs. As a result, D.12-04-045 stated the need to improve the method used for these calculations<sup>19</sup>. During the course of the 2012-14 DR portfolio proceeding, subsequent cost-

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<sup>19</sup> Section 6.2.4.3

effectiveness workshops, and more recent staff research, a large number of options have emerged:

1. Loss of load probability or loss of load expectation (LOLP/LOLE) models: Each IOU has an LOLP/LOLE model which they use for planning purposes. The IOUs have provided testimony that they believe that using LOLP/LOLE models will result in more precise and accurate values. Other stakeholders have protested the use of LOLP/LOLE models for various reasons, including that these models use proprietary software, the inputs include confidential data, and the models are run infrequently. The CPUC has determined that “transparent” models, which use only publicly-available software and data, are preferred.
2. E3 default (simple) model: This is a fairly simple model, which spreads the residual capacity value over the 250 hours of the year with the highest demand. This method was used during the IOUs 2012-14 budget application. There was some variation between the IOUs in how exactly how the allocation among the 250 hours was made.
3. E3 default (simple) model using fewer hours: In the IOUs 2012-14 budget application, SDG&E argued that using the same method, but spreading the value over the top 100, rather than 250, hours was more accurate.
4. R factor model<sup>20</sup>: At a workshop in October 2012 on Demand Response cost-effectiveness, the IOUs suggested a mathematical function, called the “R factor,” which mimics their LOLE output.
5. E3 new model<sup>21</sup>: At a workshop in October 2012 on Demand Response cost-effectiveness, E3 suggested a new, somewhat more complex version of their default model. They subsequently provided more detail of this model, which can be found in the attached paper. A somewhat more extensive version of this model can also be used to develop a two-step A factor that accounts for availability and dispatchability.
6. Probabilistic reliability modeling: This model is under development in the Resource Adequacy proceeding (R.11-10-023)<sup>22</sup>. This probabilistic reliability model, run by Energy Division, could be used to allocate the residual capacity value to each hour of the year, as well as determine some of the adjustment factors. This would likely be a superior method because at least some demand-side programs (i.e., those that are dispatchable such as Demand Response) could be included in the model along with supply-side options.

While the preferred method is to use option #6, until such time as this model has been approved by the Commission the LSEs shall use option #5 for both allocation of the residual capacity

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<sup>20</sup> See, for example, SCE’s comments at

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M029/K556/29556665.PDF>, pp. 7-8, Figure II-2.

<sup>21</sup> E3 ELCC model was first proposed at a workshop on Demand Response Cost-effectiveness on October 19, 2012: [http://www.cpuc.ca.gov/NR/rdonlyres/F8619E63-F001-4EA6-B512-EF4B6B9CD65E/0/DR\\_Costeffectiveness\\_Workshop\\_final.pdf](http://www.cpuc.ca.gov/NR/rdonlyres/F8619E63-F001-4EA6-B512-EF4B6B9CD65E/0/DR_Costeffectiveness_Workshop_final.pdf) (slides 27-38). E3’s Recap model, a more recent

version, can be found at [https://ethree.com/public\\_projects/recap.php](https://ethree.com/public_projects/recap.php).

<sup>22</sup> <http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/Probabilistic+Modeling.htm>

value and the determination of the A factor, as discussed below. The DR Cost-Effectiveness Report will be adjusted accordingly.

*Adjustments to the generation capacity value:* Because DR reduces end-use load, it also reduces the reserve margin of operating generation facilities that provide reserve generation to respond to system contingencies. The applicable adopted reserve margin will be used to adjust the generation capacity value upward when applied to the MW impacts of the DR program. In addition, CTs incur a heat rate efficiency penalty when operating during the hot summer on-peak periods when the capacity is needed the most. This CT Summer Peak Performance Penalty reduces the energy produced by the CT and therefore reduces both energy production and energy revenues. The Peak Performance Penalty, in the form of a percentage reduction of the generating capacity of the CT during the summer months, will also be applied to adjust the capacity value upward. The calculation of avoided capacity costs will also take into account avoided line losses.

*Adjustments for individual DR programs:* The generation capacity value of a DR program without usage or availability constraints would be equivalent to the full CT residual capacity cost. Therefore, this cost will be the maximum capacity value. To the extent that a DR program has usage and availability constraints, this maximum value should be adjusted downward. Three adjustment factors for avoided capacity cost were included in the 2010 Protocols: Availability (A Factor), Notification Time (B Factor) and Trigger (C Factor). Two additional factors are being added to these 2014 protocols. The F factor is an optional adder (i.e., greater than 100%) that can be applied to those DR resources that are flexible enough to be useful to the system operator to mitigate the effects of intermittent generations. The G factor is also an optional adder, which should reflect any additional value of a DR program which can be called locally in a constrained area. The adjustment factors are designed to reflect the program characteristics that constrain or add to the optimal use of DR dispatching. These factors are discussed below.

**The A Factor** is intended to represent the portion of capacity value that can be captured by the DR program based on the daily and monthly availability of the program, and the frequency and duration of calls permitted. A program that could be called in every hour that a generation capacity constraint might be experienced by the utility would have an A Factor of 100%. As discussed above, a new model created by E3 is temporarily adopted for this calculation, and will be replaced in the future by probabilistic reliability modeling to determine the A factor.

For **the B factor** calculation LSEs were directed to examine past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls. In other words, decisions about when to call day-ahead events are based on the best available information the day before the event occurs. However, the need for DR is based on conditions (particularly weather), which can change in the course of 24 hours. By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program. As an example, such an analysis would identify when load and weather forecasts would have initiated a DR call a day ahead as compared to when DR curtailments were actually needed in real-time. However, in the 2012-14 DR portfolio proceeding the IOUs were able to only apply this method to distinguishing

between day-of and day-ahead programs. The three IOUs had slightly different results, and Commission staff subsequently provided guidance<sup>23</sup> to the IOUs to use a B Factor of 100% for all day-of programs and 88% for all day-ahead programs.

It is difficult to determine the exact, relative value of the various notification times. As it becomes more common for Demand Response to be bid into CAISO markets it will be easier to quantify these values. It may be possible to eventually determine this value using probabilistic reliability modeling. However, until a more exact measurement can be made, LSEs are instructed to use the following B Factors:

**Table 7**

Notification Time	B Factor
5 minutes or less	100%
15 minutes	97%
30 minutes	94%
Day Of, greater than 30 minutes	91%
Day Ahead or greater	88%

**The C factor** should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions. Therefore, a C factor should be determined so that programs with less flexible triggers can be de-rated. In the past, each LSE was directed to propose a method for determining the C factor, and to clearly explain the method used and each step of the process described. In the 2012-14 DR portfolio proceeding PG&E used a C Factor of 95% for its air conditioner cycling programs and its Base Interruptible Programs, and 100% for all other DR programs, while SDG&E and SCE used a C Factor of 100% for all programs. The January 2011 Guidance on Cost-effectiveness instructed the IOUs to use a 'C factor' of 95% for any program which cannot be triggered at the discretion of the utility, and to otherwise use 100%.

However, subsequent CPUC analysis in the May 1, 2013 Staff Report on SCE's & SDG&E's Summer 2012 DR Programs<sup>24</sup> found that the IOUs are not triggering their DR programs in an optimal manner. This reluctance on the part of the IOUs to call their DR programs indicates a lack of trigger flexibility. As a result, a new method for determining the C Factor is needed.

All DR programs provide insurance against catastrophic emergencies. This is the primary value that traditional "interruptibles" programs, the predecessor of modern DR, provided. DR can provide increasingly significant value by avoiding purchases of high-priced generation. However, DR programs only accomplish the latter to the extent that they are dispatched. Therefore, C factors will be based partially on each DR program's historic number of called events.

<sup>23</sup> January 2011 Energy Division Guidance on Cost-Effectiveness, available at <http://www.cpuc.ca.gov/NR/rdonlyres/92C54F59-8D88-446A-846A-1747628C0F33/0/GuidanceJanuary2011.pdf>

<sup>24</sup> available at <http://www.cpuc.ca.gov/PUC/energy/Demand+Response/> (scroll down to "Staff Report on SCE's & SDG&E's Summer 2012 DR Programs")

While it is difficult to determine the relative worth of DR's insurance value, as compared with its price-mitigation value, it will be assumed, somewhat arbitrarily but not unreasonably, that each of these is roughly equal. Therefore, a minimum C factor of 50% will be assigned to all DR programs, based on the insurance value that all DR provides. The remaining C factor value will be based on a dispatchability factor, which will be defined as the ratio between the program's average annual number of hours of called events to the maximum number of annual event hours, averaged over all each year for which data is available, beginning with 2006. This will determine the C factor for all programs for which the LSE is the authority deciding if and when to dispatch the program. Programs which are bid or scheduled into wholesale markets and dispatched by the system operator include a must-offer obligation. Hence, a C factor of 100% is assigned to these DR resources, with the understanding that additional experience with these programs may, in the future, suggest otherwise.

The formula for the calculation of the C factor is as follows:

For any DR program that is bid or scheduled into wholesale markets and directly dispatched by the CAISO: 100%

For any DR program that is dispatched by an LSE:

$$\text{C Factor} = 50\% + \frac{(\text{annual average number of event hours from 2006 to present})}{(\text{maximum number of annual event hours})}^{25}$$

For example, a program which is operated year-round and has a maximum number of 15 call hours per month has an annual maximum number of 180 event hours. If the program has been in existence for four years, and was called 100, 120, 20 and 140 hours respectively during those years, then the average of  $100 + 120 + 20 + 140$ , divided by 180, or  $95/180$ , or .54. This number will determine the dispatchability factor. Since the dispatchability factor makes up half of the C factor calculation, the dispatchability factor is half of .54, or 27%. That is added to the 50% insurance value to get a total C factor of 77% for this program. Details of this calculation for each DR program must be included in the workpapers.

LSEs should keep in mind that D.10-06-034 issued in Phase 3 of R.07-01-041 adopted a multi-party settlement and reduced the amount of reliability-based and emergency-triggered demand response programs that count for Resource Adequacy from 3.5% of system peak in 2010 to 2% of system peak in 2014. Although the settlement adopts caps on the MWs that count for Resource Adequacy, the settlement removed the enrollment caps on reliability-based and emergency-triggered demand response program. Any C Factor analysis applied to emergency based DR programs should make a clear distinction between enrolled MW up to the 2% cap and enrolled MW over and above the 2% cap. To the extent a utility applies a capacity value to emergency based DR above the 2% cap, the utility must clearly demonstrate that the impact of the emergency based DR above the 2% cap actually reduces the identified capacity needs used

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<sup>25</sup> Note that if the maximum number of annual event hours has changed since 2006 that this should be taken into account when making the calculation.

for utility and CAISO capacity and RA planning and leads to a commensurate reduction in capacity or RA procurement.

**The F Factor** is an adder, which means that, like the E Factor, its minimum value is 100%. ~~which~~ It provides additional value for those DR resources which are particularly flexible, and can provide the CAISO with added value in that they are particularly useful for responding to intermittent generation. Characteristics of flexible DR may include programs which are:

- Capable of making economic bids into CAISO markets and subject to a must-offer obligation according to the Flexible Resource Adequacy Must Offer Obligation,
- Capable of ramping or sustaining output for three consecutive hours, and
- Capable of rapid response (i.e., have a short customer notification time).

LSEs must include any proposals to use this flexibility adder in their workpapers. The proposals should include an explanation of why the adder is needed, and an analysis of how the magnitude of the adder was determined. LSEs should file their cost-effectiveness analyses in the DR Cost-Effectiveness Reports of affected DR programs, and their DR portfolios, both with and without the ~~any F factor adders~~.

**The G Factor** accounts for those DR resources which can be called locally in geographical regions that are resource-constrained. The G Factor is an adder, which means that, like the E Factor, its minimum value is 100%. Starting with these 2014 Protocols, LSEs may propose this adder for any DR program which can be called locally in any region which is facing constraints that put it at a higher than normal risk of experiencing generation capacity shortages. LSEs must include any proposals to use this geographical adder in their workpapers. The proposals should include an explanation of why the adder is needed, and an analysis of how the magnitude of the adder was determined. LSEs should file their cost-effectiveness analyses in the DR Cost-Effectiveness Report of affected DR programs, and their DR portfolios, both with and without ~~any capacity factor adders~~ the G factor.

In the event that an LSE does not submit a G factor for some or all of their programs, the default G factor values will be as follows:

For SDG&E, the default G factor value shall be 110%.

For SCE:

- For DR programs that can only be dispatched in SCE's entire service territory, the default G factor value shall be 100%.
- For DR programs that can be dispatched only in the local resource adequacy areas of Big Creek-Ventura or the L.A. Basin, the default G factor value shall be 105%

For all other LSEs other than SDG&E and SCE, the default G factor value shall be 100%.

**2) *Avoided Energy Costs:*** The Avoided Cost Calculator calculates hourly avoided costs of energy in both the day-ahead and real-time markets based on historic hourly shapes and a forecast of the average value of wholesale energy in each year. These hourly energy values serve as the basis for the valuation of energy savings resulting from demand reductions. The hourly shapes of the day-ahead and real-time markets are derived from historical CAISO data. Hourly historical Locational Marginal Prices (LMPs) at each of the load aggregation points are normalized by daily gas spot prices to adjust for the underlying volatility of the gas market. The resulting shapes provide a representative snapshot of the dynamics and trends in each market that is used to shape the average market price in each year.

The annual average market price is based on market forwards for electricity contracts at NP15 and SP15 obtained from Platts. Between 2010 and 2014, these forwards are used directly as the annual value of energy. Beyond 2014, the average market price is calculated as the product of the average market heat rate, which is assumed to remain level after 2014, and the forecast of burnertip gas price in California. The annual average market price calculated in this manner serves as the annual average for both the day-ahead and real-time markets.

The calculation of avoided energy costs will take into account avoided line losses. The incremental cost of any additional generation resulting from a load-shifting program will be taken into consideration based on the expected electricity prices during the time that the additional electricity is used.

The DR Cost-Effectiveness Report estimates energy benefits based on the straightforward product of on-peak energy avoided costs, loss factor, and avoided energy usage. This value estimate is supplemented by an adjustment factor that allows parties to value DR under alternate energy price scenarios. LSEs are required to use the simple evaluation approach presented herein, but are allowed to apply an Energy Adjustment Factor (E Factor). LSEs may use the energy adjustment factor to reflect the correlation between electricity prices and the times when DR program events are expected to occur, based on the times in which the program will be available, constraints on the use of the program, and the probability distribution of and correlations between the trigger conditions under which events can be called under that program. The derivation of the E factor must be provided in the workpapers.

In the past, parties have discussed the use of option pricing models to value DR. While this has theoretical value, such an approach is far from an easily understood and transparent approach. LSEs may, however, incorporate an option pricing approach in the “E Factor” analysis. In that case, however, the LSE shall provide justification for the adjustment factor in their workpapers provided as part of the cost-effectiveness analysis. Such justification will include all input data and modeling in spreadsheets that will allow Commission staff and interested parties to replicate the LSE’s results.

**3) *Avoided Transmission and Distribution Costs:*** As a result of DR programs, utilities may defer and/or reduce transmission and/or distribution capacity investments (and thus avoid T&D costs) in local areas experiencing load growth or other system constraints. The 2010 Protocols used avoided T&D values submitted in each IOU’s General Rate Case as the basis for the avoided T&D calculation. These values were allocated to individual hours based on the hourly

temperatures in each climate zone. This approach resulted in an allocation of T&D value to several hundred of the hottest hours of the year. This information was then used to determine a monthly avoided T&D cost, which when combined with each program's monthly load impacts, determines the potential monthly avoided T&D cost of the program.

Since that time, a new model for avoided T&D capacity costs was developed by E3 for use in the California Net Energy Metering Ratepayer Impacts Evaluation<sup>26</sup>. This model separately calculates transmission avoided costs for subtransmission "downstream" of the CAISO and distribution system avoided costs, for each IOU.

Subtransmission-level avoided costs are based on transmission avoided costs in \$/kW-year filed by the IOUs in GRC or other recent proceedings. This cost is allocated over the hours in the year in which the transmission systems would be likely to experience constraints, based on both system peak and substation demand levels.

The model for distribution-level avoided costs is more complex. The IOUs must provide confidential lists of distribution system project upgrades which are planned for the next five to ten years. Using this information, forecasts of load growth, and known capacity constraints in the project areas, E3 calculates the costs savings that could occur if the projects are deferred. This "Present Worth" method is more accurate than the previous method. However, it does have the disadvantage that it uses confidential data to determine results. While the Commission normally discourages the use of confidential data in cost-effectiveness analysis, an exception is made in this case because of the difficulty in determining reasonable and consistent values for avoided T&D costs, until and unless another method emerges which uses only publicly-available data.

The accuracy of this model depends on the provision of detailed, accurate and timely information from the IOUs. The IOUs are expected to comply with the need for this information so that accurate avoided T&D capacity costs can be determined.

LSEs other than the IOUs should continue to use the method described in the 2010 Protocols to determine this avoided cost. For all LSEs, the avoided cost of T&D capacity will be increased to account for line losses.

The avoided T&D capacity cost must be matched with the characteristics of individual DR programs by using the "D factor," which adjusts the T&D value for each program. Throughout the years that demand response stakeholders have discussed the concepts related to cost-effectiveness, the terms "right time", "right place", "right certainty" and "right availability" have been used to describe the match of allowable DR operations to utility T&D system needs and avoided costs. The various criteria are intended to limit the application of the avoided T&D costs to programs that actually avoid or defer T&D investment. A specific method for calculation of the D factor is not proposed here, but LSEs are expected to base their D factors on the criteria below, and explain in their workpapers how the D factor for each DR program was determined.

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<sup>26</sup> [http://www.cpuc.ca.gov/PUC/energy/Solar/nem\\_cost\\_effectiveness\\_evaluation.htm](http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm). See Appendix C, p. 40.

The D factor for each DR program should be based on the following criteria:

**Right Time:** DR is or can be in place in time to defer some or all of the costs of planned or needed distribution system upgrades (i.e., before local conditions become severe enough to require upgrades)

**Right Place:** DR programs exist in areas where additional distribution capacity is needed and can be relied upon for local T&D equipment loading relief (e.g., can be dispatched just in the local area, not only system-wide, and ~~or~~ are located in areas where load growth would result in a need for additional delivery infrastructure but for DR).

**Right Certainty:** There is sufficient certainty that DR can provide the long-term demand reductions to defer upgrade costs. For example, there must be a sufficient number of customers and the appropriate types of DR to provide a reasonable level of certainty that needed demand reductions can be provided.

**Right Availability:** DR will be available when needed. This is a similar calculation as for the A factor, although specific to T&D needs. It should take into account that for DR to be able to avoid sub-transmission and distribution investment, it must be possible to call the program to reduce circuit loading when it may occur, which may or may not be at times when the system is experiencing a generation peak event.

The default value of the D factor will be 0%. In other words, it will be assumed that a given DR program does not avoided or defer any transmission or distribution upgrades unless LSEs can show otherwise, at both the sub-transmission and distribution levels. LSEs must provide, in their workpapers, and explanation of how the above criteria apply to each DR program.

### **Section 3.C: Bill Increases and Reductions**

Bill increases and reductions are included only in the Participant Test. They are calculated from the perspective of end-users who participate in DR programs. However, because they occur only in the Participant Test it is only necessary to calculate them for default DR programs which do not have an opt-out provision.

This calculation can be complex because end-users generally switch from one rate to another when signing up or defaulting onto a DR program. Hence, a participant's bill reduction (or increase) is the difference between the actual bill received by the participant, *less any incentives paid*, and the bill the participant would have received had the participant not signed up for DR.

For example, in a program which changes the participant's rates but does not provide any incentives, such as CPP, the bill reduction (or increase) would be the difference between the actual bill and the bill the participant would have received had the participant stayed on the previous rate. For a program which does not change the rates but simply provides an incentive structure on top of the existing rate structure, such as an Air Conditioner Cycling Program, the bill reduction (or increase) is simply the total load drop (or increase) during DR events multiplied by the participant's rate. For a program which both changes rates and provides

incentives, the incentives must be subtracted from the actual bill before the difference between the actual bill and the bill that would have been received under the old rates is calculated.

DR programs which provide new customers with bill protection should be able to generate this information fairly easily. However, for other programs, the expense of accurately calculating these bill reductions and increases may be very large, and not worth the cost given the relatively small values likely for this data. Hence, when assessing default DR programs which do not have an opt-out provision, the utilities may, if necessary, approximate these values using load impacts estimated using the established Load Impact Protocols, and a reasonable and transparent method. It may also be easier for the utility to calculate one number that is the sum of customers' bill reductions and incentives paid, which is acceptable for the participant test. However, a separate value for the incentives paid must still be calculated for the PAC and RIM tests.

### **Section 3.D: CAISO Market Participation Revenue**

The CAISO currently has ~~two~~ three products available that allow for DR to participate directly in wholesale energy markets. These are the Proxy Demand Resource, ~~and~~ Participating Load, and Reliability Demand Response Resource products. ~~The CAISO anticipates that a third product, the Reliability Demand Response Resource program will be available for emergency DR resources in the 2<sup>nd</sup> quarter of 2014.~~ Product specifications and must-offer requirements for flexible capacity, which DR will be eligible to provide, are currently in development. Any revenues earned by an LSE or third party DR provider from CAISO markets through direct participation of DR should be counted as a benefit in cost effectiveness calculations using these protocols. No utility DR programs have been designed with the explicit intention of bidding or self-scheduling into these markets<sup>27</sup>, but such programs are anticipated in the future. ~~It is therefore not possible right now to adopt a specific method for incorporating such revenues earned by DR.~~ For those DR programs that can participate directly in CAISO markets, LSEs should provide information regarding how that program will be bid into the CAISO markets. Such information should include which services can be provided, the ~~anticipated~~ minimum and maximum number of hours and MWs that will be bid into each market, any rules or agreements that limit or enhance the ability of the utility to bid DR into these markets, and how CAISO market revenues will be shared between the utility, customer and, if applicable, aggregator. The rules and bidding strategies for DR participation in these markets may be complex. Nevertheless, the computation of these revenues should be presented in a clear and transparent manner.

### **Section 3.E: Capital Costs to LSE**

This cost includes the fixed (capital) costs actually incurred by the LSE for equipment, IT and other investments which are required for particular DR programs and have a useful lifetime that is **greater than** the period of time over which the cost-effectiveness analysis is done (i.e., the reporting period, which is usually a three-year budget cycle). Any investments which have a useful lifetime of less than the reporting period should be considered administrative costs. Capital costs will be amortized over the lifetime of the investment as well as over the reporting period, to determine the low and high values, respectively, which will be used in the sensitivity analysis. For each investment, the LSE shall explain the details of the cost (e.g., types of equipment purchased, type and use of the IT investment) and how the lifetime was determined.

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<sup>27</sup> PG&E's IRM2 pilot is an exception. It commenced bidding into CAISO energy markets in 2014.

Note that all capital costs must be included in the cost-effectiveness analysis of each DR program, even if those costs are budgeted elsewhere.<sup>28</sup>

For each DR program which requires capital investment, LSEs should submit a separate Capital Amortization Period for each investment, which will be used as part of the calculation of the high, low and base case values for the annual cost of each capital investment. If it is not possible to determine a Capital Amortization Period for a particular program, a default value determined by Commission staff will be used. The default value is currently 10 years for DR equipment and 5 years for IT equipment and software. Commission staff

For each capital investment, the maximum cost of that investment occurs when the equipment is used only during the reporting period and then discarded. The minimum cost occurs when the equipment is fully used by all participants, none of whom drop out of the program, for each year of its useful lifetime. Accordingly, we will use these two values for the high and low values in the sensitivity analysis, respectively. For the high value, the total cost of the investment will be amortized over the reporting period (usually three years), and for the low value, the investment will be amortized over its useful lifetime, based on the value supplied by the LSE. If the LSE does not submit a value for the useful lifetime of each investment, the default value of 10 years (or 5 years for IT) will be used.

The base value of each capital investment will be estimated as the halfway point between the low and high values. The formula for this calculation is:

Base value = low value +  $\frac{1}{2}$  \* (high value – low value)

### **Section 3.F: Capital Costs to Participant**

This cost includes the fixed (capital) costs actually incurred by a program participant when installing equipment designed to facilitate the participant's ability to provide demand reductions. It also includes operations and maintenance cost of that equipment, as well as removal costs (less salvage value), and any other equipment-related costs associated with DR-enabling equipment installed by the participant. If a participant receives full or partial rebates for DR-enabling equipment purchases from the utility or any other known source, the cost of those rebates must be subtracted from the purchase price to determine the total capital costs incurred by the participant<sup>29</sup>. Note that capital costs do *not* include costs such as the participant's time spent in arranging the installation, or other indirect costs which are more properly accounted for as participant transaction costs or value of service lost. Note that all capital costs must be included

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<sup>28</sup> For example, if a customer receives an equipment rebate or other assistance as part of a rebate program such as Auto DR, and subsequently enrolls in a critical peak pricing program, the costs of the equipment rebate are considered capital costs of the critical peak pricing program. For customers who have received equipment rebates but have not yet enrolled in a DR program, a reasonable estimate should be made, based on program history, of the proportion of those customers who will ultimately enroll in each DR program.

<sup>29</sup> For example, if a customer purchases a piece of equipment for \$1200, receives a rebate for \$400, pays \$100 for equipment installation, and there are no operations, maintenance or removal costs, then the capital cost to the participant is \$1200 - \$400 + \$100 = \$900.

in the cost-effectiveness analysis of each DR program, even if those costs are budgeted elsewhere.

As with the Capital Costs to LSE above, for each DR program, LSEs should submit a Capital Amortization Period for each investment, which will be used as part of the calculation of the high, low and base case values for the annual cost of each capital investment. If it is not possible to determine a Capital Amortization Period for a particular program, a default value determined by Commission staff will be used. All calculations for Capital Costs to Participant remain the same as for Capital Costs to LSEs, as detailed in Section 3.F.

### **Section 3.G: Incentives Paid**

This category consists of the total amount of all capacity and energy incentives paid by the utility to participants for “pay for performance” programs. In the case of contracts between a utility and a third-party aggregator, the incentives paid are considered to be the total amount of all capacity and energy incentives paid by the utility to the third-party aggregator.

The cost of incentives paid to participating customers should be determined consistent with the forecasted usage of the DR program, determined from the Load Impact protocols, that is used to calculate avoided generation capacity and energy benefits. LSEs should calculate the expected cost of incentives, consistent with the program’s Load Impacts and Expected Call Hours. This may differ from the budgeted cost of the DR program’s incentives, which may be based on a maximum, rather than expected, number of call hours.

Most DR incentives are received by participants in the form of bill credits, although separate payments made directly from an LSE to a participant do occur. For the purposes of cost-effectiveness, the protocols do not distinguish between direct incentive payments and bill credits, and refer to either as “incentives.”

### **Section 3.H: Increased Supply Costs**

Increased supply costs are any costs incurred by the utility in providing additional electricity to ratepayers as the result of a DR program. These costs would normally be zero, as DR generally decreases electricity consumption. However, there may be programs in which electricity consumption might increase, especially during certain time periods, such as load shifting programs. In these cases, it may be appropriate to calculate this cost.

### **Section 3.I: Market Benefits**

This category of benefits includes the increased market efficiency improvements resulting from DR, such as improved overall system load factors, improved market performance (e.g., decreasing price volatility), increased overall system flexibility, and portfolio diversity benefits. Most of these benefits are difficult to quantify, and there is disagreement as to whether some of them exist at all. The exact nature of these benefits may become clearer as new research emerges and new markets for DR become available.

Electricity markets are constantly changing, and potential developments such as a capacity market could alter the methods and benefits used to value DR. However, more study is needed

of these potential benefits before they can reasonably be included in DR cost-effectiveness. The benefits that should be considered include the factors mentioned above as well as:

- **Innovation in retail markets.** Providing a DR framework can result in new retail product and pricing innovations, ultimately benefiting the customer through increased choice and a better matching of the customers' needs with choices offered by electric markets.
- **Incentive for development of efficient controls and end-use technologies.** The customer's potential for cost savings through load shifting creates a new market for technology that now has an appropriate value proposition and business case.
- **Reduced market power on peak days.** Tight supplies and/or transmission constraints that can exist on days when DR is likely to be called can lead to an excess of market power. Since most generation is already committed, generators not yet committed may have greater market power for meeting the remaining peak demand (i.e., there is less competition once most generation has already been committed).
- **Overall productivity gains by better utilizing industry investment.** Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing the fixed investment that comprise one of the largest capital investments made in a region. Improved capacity factors should result in improved electric system efficiency.

Although LSEs will not be required at this time to estimate these additional market benefits in their cost-effectiveness calculations for DR programs, qualitative analysis of these benefits should be provided, as discussed in Section 1.G above. It is important that LSEs provide this analysis, even if they believe that these benefits do not apply to their DR programs.

### **Section 3.J: Non-Energy and Non-Monetary Benefits**

Utilities, demand response program participants, and society as a whole receive non-energy benefits from participation in DR programs. These benefits are also referred to as non-monetary benefits.<sup>30</sup> There may also be non-energy or non-monetary costs, which can be included in this category as a decrement, or negative benefit, in any calculations. These benefits, by their nature, are difficult – if not impossible – to quantify. However, a considerable amount of work has been done to quantify some of these benefits for low income energy efficiency programs.<sup>31</sup> This work can be used as a starting point for understanding the non-energy benefits of DR.

Non-energy benefits (NEBs) are usually divided into three categories:

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<sup>30</sup> Non-energy benefits are somewhat different than non-monetary benefits, in that non-energy benefits may include monetary gains such as lower labor costs. Either concept may be used to provide a basis for analysis for this category of benefits, as our understanding of this type of benefit is still emerging.

<sup>31</sup> More information about the use of non-energy benefits to evaluate Low Income programs can be found in the revised final report “*Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California*” issued May 11, 2010. <http://www.liob.org/docs/LIEE%20Non-Energy%20Benefits%20Revised%20Report.pdf>

- Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
- Utility non-energy benefits, such as fewer customer calls and improved customer relations.
- Participant non-energy benefits, such as “feeling green,” being good citizens by helping to prevent outages, improved ability to manage energy use, and having a better public image (for commercial enterprises).

**Social NEBs** include “environmental benefits,” which in the 2010 Protocols were listed as a separate category of benefits. Social NEBs can be included as benefits in the calculation of the TRC test. They may not be included in the PAC, RIM or Participant Test.

Criteria emission pollutant-related costs that can be avoided by DR programs are already reflected in estimates of the generation capacity costs avoided by that DR program, to the extent that pollutant limits are required by current environmental regulation. However, environmental regulations are enacted to limit pollutants, not to limit the abatement of pollutants. There are residual benefits of avoiding criteria pollutants above and beyond the level of existing environmental regulation. In fact, the State of California Public Utilities Code allows for this benefit to be considered for interruptible (emergency DR) programs:

**743.1.** (a) Electrical corporations shall offer optional interruptible or curtailable service programs, using pricing incentives for participation in these programs. These pricing incentives shall be cost effective and may reflect the full range of costs avoided by the reductions in demand created by these programs, including the reduction in emissions of greenhouse gases and other pollutant emissions from generating facilities that would have been required to operate but for these demand reductions, to the extent that these avoided costs from reduction in emissions can be quantified by the commission. The commission may determine these pricing incentives in a stand-alone proceeding or as part of a general rate case.

There are several other environmental impacts that might be avoided depending on the specific type(s) of capacity – generation, transmission, or distribution – that the DR program is expected to defer or avoid. These potential environmental impacts include the avoided costs of criteria pollutants associated with avoided generation capacity, as discussed above. Additional impacts include, but are not limited to:

- decreased health care costs associated with lower emission levels, especially decreased air pollution;
- additional GHG mitigation benefits (over and above the avoided GHG costs)
- quantitative or qualitative job creation benefits resulting from DR programs;
- environmental justice improvements, particularly for supplying electricity in urban areas
- biological impacts;
- impacts on cultural resources;
- diminishing visual resources (e.g., due to power plant stacks or transmission towers);
- land use, including impacts of energy infrastructure on local ecosystems;

- effects on water quality/consumption; and
- noise pollution.

**Utility NEBs** can be included in the TRC, PAC and RIM tests, but should not be included in the Participant Test. Utility NEBs consist of any indirect change in costs that an LSE experiences as a result of its DR programs. This includes any changes in the number of complaint calls or service requests, any changes in customer perception or relationship to their LSE, and changes in the number of delinquent bills or disconnections. All utility NEBs included in the cost-effectiveness analysis must be documented.

**Participant NEBs** is a broad category which includes the intangible benefits that DR participants often perceive when they agree to reduce their demand during DR events. Some of these specific benefits are listed above. While these benefits are important to the participants, they should not be included in the TRC, PAC or RIM tests, since these benefits accrue only to a small number of ratepayers. These benefits should be included *only* in the Participant Test.

Although LSEs are not required to include NEBs in their cost-effectiveness calculations for DR programs, either LSEs or other parties are invited to submit evidence of the magnitude of the benefits or costs of Demand Response. However, only evidence supported with data, rather than based on speculation, to be accepted by the Commission.

In addition, qualitative analysis of these benefits is required, as discussed in Section 1.F above. An example of this type of analysis would be a discussion of the additional benefit provided by a new residential DR program which is designed to be integrated with energy efficiency and customer generation programs. Because this program provides benefits that other DR programs do not, a qualitative analysis can be made, describing the additional benefits of offering customers integrated load management solutions, as compared to the traditional approach of separate programs for energy efficiency, demand response and customer generation. The analysis should discuss the possibility of increased customer participation, reduced participant transaction costs, and possible utility cost savings in their marketing and administrative budgets.

### **Section 3.K: Revenue Gain or Loss from Sales Increases or Decreases**

These revenues are calculated only for the RIM test. For the most part, a DR program will result only in revenue loss, rather than revenue gain, but there may be programs in which electricity consumption might increase, especially during certain time periods. Also, even if a DR program results in a net revenue loss due to a DR reductions, it may make more sense to calculate this quantity separately for different time periods. In many current DR programs, there is a revenue gain during non-peak periods due to load-shifting activities.

Revenue loss (or gain) from any one utility customer is the change in consumption due to the DR program multiplied by the customer's rate, and the total revenue loss (or gain) is of course the sum of this amount for all program participants. However, like the category "bill increases and reductions" above, this calculation is complicated by the fact DR participants often move from one rate to another when joining a DR program. It is further complicated because DR participants often receive incentives, making it impossible to calculate these revenues simply by examining customer bills.

Revenue loss (or gain) should be calculated in a similar manner as bill increases (or reductions), as discussed above, so that incentives are eliminated and any change in the participant's rate structure is accounted for. Also similar to the category above, utilities are not expected to go to great expense to accurately calculate revenue gains (or losses). Hence, when calculating these values for the RIM test, the utilities may simply approximate these values, using a reasonable and transparent method, if a more precise measurement is not available. For example, LSEs usually assume that revenue losses and gains are equivalent to bill reductions and increases.

### **Section 3.L: Tax Credits**

Tax credits are not presently available for DR programs. In the event that they are available in the future, they should be considered a benefit in the TRC and Participant tests. This includes any and all federal, state or local tax credits which may become available to participants for DR equipment installation or any other cost incurred in providing demand reductions.

### **Section 3.M: Transaction Costs and Value of Service Lost**

These two categories include all of the costs to the participant, other than bill increases and equipment costs, of participating in a DR program. Transaction costs are the opportunity costs associated with education, equipment installation, program application, energy audits, developing and managing a load shed plan, etc. Examples of transaction costs are the personnel costs associated with time spent on activities such as filling out a DR program application, making decisions about whether or how to install DR equipment, developing and testing a load-shed plan, and enacting that plan during DR events.

Value of service lost includes any losses in productivity that occur because of demand reductions as well as "comfort costs," which are the losses in comfort participants may experience or perceive when an end-use become unavailable. Examples of lost productivity costs are revenue losses incurred when a business is shut down during a DR event, or the cost of food which spoils in a non-working refrigerator. Examples of comfort costs include having to walk further to use a copy machine, feeling too hot or too cold because of changes in a thermostat setting or an equipment outage, or the cost of having to change one's work hours.

These costs are significant to the participant, but difficult to assign a monetary value to. Even individuals who experience the loss of comfort generally cannot state with any certainty what monetary value they place on, for example, feeling warmer than preferred, and even when monetary values can be determined, as they often can for productivity costs, they vary widely from one person, company or industry to the next. This makes it extremely difficult to estimate these costs for the purpose of estimating DR cost-effectiveness. Direct estimation of value of service lost or productivity losses would require extensive research and customer surveying, which is likely to be expensive and yield results that are highly uncertain. For this reason, a proxy variable is used to estimate these costs.

The benefits to a participant of participating in a DR program are, for the most part, easy to estimate – they are simply the total amount of the incentives paid to the participant.<sup>32</sup> It is reasonable to assume that participants in voluntary DR programs perceive their costs as being less than the benefits, or at the very least participants perceive that they are “breaking even.” Therefore, the maximum possible value of their costs is equal to the value of the benefits. Hence, the maximum possible value of a participant’s bill increases + equipment costs + value of service lost + transaction costs is equal to the value of the benefits received. This deduction leads logically to using the amount of the incentives as a proxy measurement for participant costs, where:

$$\text{Total Participant Costs} = \text{Transaction Costs} + \text{Value of Service Lost} + \text{Capital Costs to Participant} + \text{Bill Increases}$$

$$\text{Total Participant Benefits} = \text{Incentives} + \text{Non-Monetary/Energy Benefits} + \text{Tax Credits} + \text{Bill Reductions}$$

$$\text{Total Participant Costs} \leq \text{Total Participant Benefits}$$

$$\text{Transaction Costs} + \text{Value of Service Lost} + \text{Capital Costs to Participant} + \text{Bill Increases} \leq \text{Incentives} + \text{Non-Monetary/Energy Benefits} + \text{Tax Credits} + \text{Bill Reductions}$$

Tax credits and bill increases will generally be zero, and non-monetary/energy benefits are accounted for elsewhere. Hence, the net result is:

$$\text{Transaction Costs} + \text{Value of Service Lost} \leq \text{Incentives} + \text{Bill Reductions} - \text{Capital Costs to Participant.}$$

Hence, for the purpose of calculating values for the TRC test, *for voluntary DR programs only*, LSEs should assume that the *maximum possible* value of the transaction costs and value of service lost can be approximated as the value of all incentives paid to customers plus the customers’ total estimated bill reductions minus any participant capital costs. Because this is the *maximum* value possible for this quantity, it will be used as the high value in the sensitivity analysis for most DR programs. The base value of 75% of this quantity and a low value of 50% will be used for most DR programs, as discussed below.

There are some DR programs or customers for which more precise estimates can be made. For example, evaluations of residential air conditioner cycling programs indicate that most participants do not notice any loss of comfort when their air conditioners are turned off during an event<sup>33</sup>. There are few, if any, productivity losses, and the transaction costs are relatively low – participants have to apply to the program, and arrange for a technician to install a switch or

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<sup>32</sup> While there are other benefits, such as the decreased cost of energy consumption during DR events (if energy is conserved rather than shifted), the benefit of feeling like a “good citizen,” and the benefit of feeling “green,” these benefits are already included in the category of non-energy benefits discussed above.

<sup>33</sup> See, for example,

[http://www.calmac.org/publications/Final\\_report\\_for\\_California\\_DLC\\_Program\\_Comparison.pdf](http://www.calmac.org/publications/Final_report_for_California_DLC_Program_Comparison.pdf), which found that only about one third of participants noticed that an event had occurred.

communicating thermostat on their premises, but do not have any continuing costs. For these reasons, these protocols will use 35% of incentives as base value of the proxy measurement for value of service lost and transaction costs for AC cycling programs, 60% of incentives for the high value, and 10% for the low value.

For DR programs which are not considered voluntary (i.e., those with no opt-out provision), LSEs will have to expand on the above analysis, and to the best of their abilities, provide estimates of the values of participant transaction costs, lost productivity costs and comfort costs. This type of analysis will be extremely challenging, and it would be reasonable to make estimates for these costs based on the known customer benefits, using the method above for voluntary programs as a starting point. Other possible starting points for this analysis might be suggested in the literature on partial outage costs, or based on customer participation rates in programs which have transitioned from opt-in to opt-out. As an alternative, LSEs may calculate the maximum Participant Costs as shown above for voluntary programs, and allow Commission staff to determine the base case amount.

For all other DR programs, the protocols assign a value of 75% of incentives as a proxy measurement of the base value of service lost and transaction costs, 100% of incentives as the high value, and 50% of incentives as the low value.

LSEs and other parties are encouraged to submit alternate methods for the analysis of participant costs, should they have evidence that an alternative method would improve the cost-effectiveness analysis. Alternate methods may include direct calculation of value of service lost and/or transaction costs or inclusion of quantifiable non-energy benefits.

(End of Appendix A)

# APPENDIX B

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

## 2.1.1. SUMMARY OF RECOMMENDATIONS AND PARTY POSITIONS

**Party List and Legend:**

CAISO	California Independent System Operator
Calpine	Calpine Corp.
Clean Co	Clean Coalition
CLECA	California Large Energy Consumers Association
Comverge	Comverge Inc.
EDF	Environmental Defense Fund
EnerNOC	EnerNOC
JCI	Johnson Controls Inc.
Opower	Opower
ORA	Office of Ratepayer Advocates
PG&E	Pacific Gas & Electric Company
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
TURN	The Utility Reform Network

*Blue lines indicate that the recommendations are mutually exclusive.*

Category	Reference	Recommendation	Support	Oppose	Neutral
Action Plan	2.1	The schedule outlined in the Action Plan is appropriate for meeting the goals of this WG.	CAISO Calpine Clean Co CLECA Comverge EDF EnerNOC JCI Opower ORA PG&E SCE SDG&E TURN		
Generation Capacity Value	3.1				
Disposition of Existing RA Rules  <i>These are mutually exclusive recommendations</i>	3.1.1.1.1	Existing RA rules should remain until the CPUC rules on the WG's recommendations; and DR-related RA issues should be addressed simultaneously. CPUC-adopted recommendations should be approved no later than Q4 2015, and any new changes to RA rules as they pertain to LMR DR and SR DR should become effective on January 1, 2018.	PG&E SCE SDG&E CLECA Opower EnerNOC JCI	CAISO ORA Calpine TURN Comverge	Clean Co

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Category	Reference	Recommendation	Support	Oppose	Neutral
	3.1.1.1.2	RA counting requirements should change as facts and analyses dictate and not be tied to DR application cycles. Counting should be updated if new analyses warrant, regardless of timing with the possible exception that, to simplify RA compliance, the RA counting of DR for an RA compliance year should be locked down by the preceding June (or whenever local RA requirements are issued for the subsequent RA compliance year). Ratepayers should only fund DR that meets RA and LTPP rules.	CAISO ORA Calpine EDF <sup>1</sup> TURN	PG&E CLECA <sup>2</sup> SCE SDG&E	Clean Co
Treatment of LMR DR in Resource Adequacy, Long Term Procurement Plan, and Transmission Planning Process	3.1.1.2.1	LMR DR should receive value for system capacity in the RA, LTPP, and TPP processes if they are dispatched on pre-defined hard triggers.	CAISO Calpine Clean Co CLECA Comverge EDF EnerNOC JCI Opower ORA PG&E SCE SDG&E TURN		

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<sup>1</sup> EDF supports this recommendation as a transition strategy.

<sup>2</sup> CLECA provides additional detail on its individual positions in the appendix section 5.2.

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Category	Reference	Recommendation	Support	Oppose	Neutral
<p>How to Incorporate LMR DR into RA, LTPP, &amp; TPP</p> <p><i>These are mutually exclusive recommendations</i></p>	3.1.1.2.2.1	<p>The CPUC should establish the key principles that will be used in determining how the LMR DR is properly incorporated into RA, LTPP, and TPP, including:</p> <ul style="list-style-type: none"> <li>- LMR DR should be incorporated into each planning process in such a way that the MW value of LMR DR fully offsets other resources otherwise needed absent LMR DR.</li> <li>- Adopted principles should continue to apply even as periodic changes are made to how the RA, LTPP, and TPP planning processes are carried out.</li> <li>- Non-event-based LMR DR (e.g., TOU and PLS) should continue to reduce the forecasted load, thereby reducing the RA requirement.</li> <li>- Event-based LMR DR should reduce the System RA requirement if it can meet the requirement as expressed through the appropriate HT.</li> <li>- Non-event-based LMR DR should continue to reduce the forecasted load in the unmanaged/base case scenarios thereby reducing capacity needs in the LTPP and TPP.</li> <li>- Event-based LMR DR should continue to meet the system need in the LTPP and TPP. The MW value of LMR DR should vary commensurate with the weather conditions in the planning scenarios.</li> </ul>	<p>PG&amp;E Opower EnerNOC JCI SCE Comverge CLECA SDG&amp;E</p>	<p>CAISO ORA Calpine</p>	<p>TURN Clean Co</p>

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

Category	Reference	Recommendation	Support	Oppose	Neutral
	3.1.1.2.2.2	This recommendation captures avoided capacity value by employing hard triggers and pre-nominated LMR DR megawatt quantities that target and beneficially affect the metrics that drive capacity needs. LSEs can nominate a quantity of dispatchable LMR DR for one or all three capacity types. For RA system capacity, the CEC would reduce its short-term forecast by the nominated LMR DR quantity and the adjusted forecast used to calculate RA supply capacity requirements. For LTPP authorized capacity, the CEC would adjust its long-term IEPR CED forecast by the nominated LMR DR quantity and the adjusted forecast used to calculate long-term capacity needs. For avoided flexible capacity, the ISO would adjust the super-peak flexible capacity quantity by the quantity of LMR DR nominated.	CAISO ORA EDF Comverge Calpine <sup>3</sup>	PG&E SCE SDG&E	TURN CLECA <sup>4</sup> Clean Co
	3.1.1.2.2.3	The CPUC should examine the potential for non-event based LMR DR and ways to incent IOUs and DR aggregators to expand this preferred resource.	EDF Clean Co		PG&E SCE SDG&E TURN
How to Set the “Hard” Trigger  <i>These are mutually exclusive recommendations</i>	3.1.1.2.3.1	The HT should be based on: system load, reliability/emergency conditions, or dispatch of the SR component of a DR program. It could vary by program, based on the specific reliability design and where it fits into the overall resource portfolio. It should apply only to event-based LMR DR programs, and soft triggers may continue to be used. A study should be conducted to determine the appropriate hard triggers for IOU LMR DR programs, and submitted to the CPUC in August 2015.	JCI CLECA PG&E SCE SDG&E Opower Clean Co EnerNOC Comverge	CAISO Calpine ORA	
	3.1.1.2.3.2	LSEs dispatch a pre-nominated amount of LMR DR when the metric that affects that particular avoided cost is forecast to reach the level that set the infrastructure investment or procurement need in the first instance.	CAISO ORA EDF Calpine	PG&E EnerNOC SCE Comverge SDG&E	CLECA

<sup>3</sup> Calpine could support this approach as long as the triggers are sufficiently high. Calpine remains concerned about the potential for the uneconomic dispatch of DR under this approach.

<sup>4</sup> During test period

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

Category	Reference	Recommendation	Support	Oppose	Neutral
	3.1.1.2.3.3	Hard triggers should be price-based and when LMR DR is dispatched, it should have the potential to set clearing prices in CAISO markets.	Calpine	PG&E CLECA EnerNOC SCE Comverge CAISO ORA SDG&E	
	3.1.1.2.3.4	Adopt 3.1.1.2.3.2, except apply it only to five summer months and/or require dispatch based on a higher trigger.	TURN CLECA <sup>5</sup>	PG&E SCE Comverge CAISO Calpine <sup>6</sup> ORA SDG&E	
	3.1.1.2.3.5	Adopt 3.1.1.2.3.1, except apply it only to five summer months.	EnerNOC	Calpine <sup>6</sup> ORA SDG&E	CAISO PG&E Clean Co
Hours for DR and RA	3.1.1.3.1	The CPUC and CAISO should undertake a review of the RA measurement hours for LMR DR and SR DR. If it is found that the peak load during the winter or summer months have shifted outside of the current required DR availability hours, the CPUC and CAISO should revise their RA requirements for both LMR and SR DR. Any recommended changes to DR measurement hours should be developed through analysis by the appropriate entity to identify the proper hours when both types of DR can meet system and flexible RA needs.	PG&E Calpine Opower CLECA CAISO Comverge ORA EDF SDG&E	EnerNOC	TURN Clean Co SCE
Separating Flexible RA Requirements from Generic RA Requirements	3.1.1.4.1	An SR DR resource should be allowed to provide Flexible RA capacity without providing underlying System RA. Supply Resource DR resources providing only Flexible RA would be required to meet only the MOO for flexible resources. Similarly, LMR DR resources should be allowed to only reduce the Flexible RA requirement without meeting the availability requirements to reduce the System RA requirement.	JCI EDF PG&E TURN Opower CLECA Clean Co Comverge		CAISO <sup>7</sup> SCE Calpine ORA SDG&E

<sup>5</sup> CLECA supports this recommendation IF the CPUC's preferred approach is 3.1.1.2.3.2 instead of 3.1.1.2.3.1.

<sup>6</sup> If these approaches are implemented, then DR should only count for RA in the months in which it is subject to a hard trigger.

<sup>7</sup> CAISO: There is no MOO for load modifying resources. LMDR can elect to avoid only flexible capacity or elect to avoid multiple capacity types based on the LMDR owner's willingness to accept the hard triggers for each capacity type. MOO is a term that applies to supply resources.

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Category	Reference	Recommendation	Support	Oppose	Neutral
Enhancements to the DR Load Impact Protocols	3.1.1.5.1	The DRMEC, as the body responsible for overseeing the DR Load Impact (LI) Reports, should lead in developing solutions for the following issues: weather normalization of ex post load impacts; address potential undervaluation of temperature-sensitive DR if load impacts are derived from the coincident load and not the non-coincident load; and consideration of valuing AC cycling at higher than 1-in-2 weather conditions (e.g., 1-in-10 conditions).	PG&E EDF CLECA Clean Co CAISO EnerNOC SCE Comverge ORA SDG&E		TURN Calpine
	3.1.1.5.2	The DR LI Protocols should be modified to provide parties with at least 3 weeks (from the existing 5 business days) to review the draft LI Reports. In addition, a webinar is suggested to provide the draft results.	ORA EDF Clean Co CAISO EnerNOC Comverge CLECA	PG&E SCE SDG&E	TURN Calpine
	3.1.1.5.3	The LI Protocols should detail the methods for forecasting the hour-to-hour capability of LMR DR in alignment with applicable planning standards. The DR LI Protocols should also ensure an ex-post hour-by-hour LI methodology is established that allows the CPUC to perform a compliance check on the performance of dispatchable LMR DR and how well it avoided infrastructure investments and procurement costs.	CAISO ORA EDF Clean Co	PG&E EnerNOC SCE Comverge CLECA SDG&E	TURN Calpine
	3.1.1.5.4	The CPUC should develop a robust means to incent IOUs and DR providers to pursue actions that increase the probability that California's electricity future will reflect high time-variant rates scenarios that best support achievement of state goals, using a range of IEPR load forecasts.	EDF Opower Clean Co EnerNOC	TURN Comverge	PG&E CAISO SCE Calpine ORA CLECA SDG&E

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Category	Reference	Recommendation	Support	Oppose	Neutral
Use of LMR DR to Meet CAISO Forecast of CAISO Demand (CFCD) and Operating Reserves Requirements	3.1.1.6.1	The CAISO should adjust the CFCD to impact its operating reserve requirement according to IOU forecasted dispatches in the day-ahead DR forecast. The CAISO has indicated that it will consider adjusting its CFCD for operating reserve procurement in the day-ahead market for LMR DR once CPUC-approved HTs are implemented and the IOUs establish a consistent track record of dispatching LMR DR programs at committed levels over a period of 2-3 years. The IOUs will continue to timely notify the CAISO of their LMR DR capability by hour and sub-LAP in their DR forecast.	PG&E TURN Opower CLECA Clean Co EnerNOC JCI SCE CAISO ORA EDF SDG&E		Comverge Calpine
	3.1.1.6.2	To the extent possible, the CAISO should ensure that the dispatch of LMR DR is economic, perhaps through reflecting LMR DR in load bids into its day-ahead market.	Calpine EnerNOC JCI	CAISO ORA	PG&E TURN Clean Co SCE Comverge CLECA SDG&E
DR Cost Effectiveness A-Factor	3.1.1.7.1	The CPUC should work with parties to revise the DR Cost Effectiveness (CE) Protocols. The A Factor should be modified to incorporate the LOLP/LOLE approach using publicly available information and more accurately quantify the capacity value of DR programs by more accurately reflecting the value of the highest peak hours. After this is complete, consideration can be made as to if, and if so how, this should factor into the DRPC for RA and LTPP.	PG&E Opower CLECA Clean Co SCE EDF	EnerNOC Comverge SDG&E	TURN CAISO Calpine ORA
<b>Avoided Local Capacity Value</b>	<b>3.1.2</b>				

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

Category	Reference	Recommendation	Support	Oppose	Neutral
Requirements for LMR DR to Meet Local Reliability Needs	3.1.2.1.1	The WG should commission a study consisting of analysis as well as benchmarking to develop a framework to establish a transparent set of requirements for LMR DR to meet a local reliability need in the RA, LTPP, and TPP. The study should be overseen by IOUs (including oversight by planning departments) and conducted by an independent third-party consultant with review and input from stakeholders including the CAISO and members of this WG. This study should consider generic requirements for LMR DR to provide local capacity value in the planning processes. Until a CPUC decision on the study, the treatment of LMR DR for Local RA requirements should be consistent with how LMR DR should not change.	Clean Co CLECA Comverge EDF EnerNOC JCI Opower PG&E SDG&E SCE	CAISO Calpine ORA	SDG&E TURN
	3.1.2.1.2	The ISO does not believe it is appropriate to reduce short-term or long-term local capacity needs based on the potential availability of dispatchable load modifying demand. To manage the grid post-contingency, the ISO must have foreknowledge, control, and dispatchability over the local capacity resources so that it can return the system, in accordance with applicable reliability standards, to its pre-contingency state within 30-minutes. By their nature, LMRs are not the type of resources the ISO relies on to manage the system post contingency, therefore, it would be imprudent to displace dispatchable supply capacity with dispatchable LMR DR capacity.	CAISO Calpine ORA	PG&E Clean Co EnerNOC JCI Comverge CLECA SDG&E	SCE TURN
	3.1.2.1.3	The IOUs and CAISO can enhance their communications such that at least some “event-based” LMR DR resources are visible and accessible to CAISO operators in adequate time to manage a contingency in a local area. The CAISO and IOUs should make the effort to make some such resources useful to operators managing local contingencies.	TURN SDG&E EDF PG&E Opower CLECA Clean Co EnerNOC JCI SCE Comverge EDF	CAISO	Calpine ORA
<b>Avoided Flexible Capacity Value</b>	<b>3.1.3</b>				

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

Category	Reference	Recommendation	Support	Oppose	Neutral
Requirements for LMR DR to Meet Flexible Capacity Needs  <i>These are mutually exclusive recommendations</i>	3.1.3.1.1	The Flexible Capacity value for LMR and SR DR should continue to be calculated using the DR LI Protocols, as it is today or revised in the future. The Flexible Capacity value of LMR DR programs should reduce the short-term Flexible Capacity need for the LSE. The Flexible Capacity value of LMR DR programs should contribute to meeting the long-term Flexible Capacity need for the LSE. Non-event based LMR DR should be capable of reducing the Flexible RA need. Qualifications for event-based LMR DR to reduce the Flexible Capacity need should include a HT, a minimum number of hours per month of availability, no locational dispatch requirement, and an appropriate mechanism to ensure CAISO has operational awareness of available LMR DR that can reduce the ramping need on a day-ahead or day-of basis. The HT should be when the forecast 3-hour net load ramp meets or exceeds the category 3 level.	PG&E SCE Clean Co	CAISO Comverge Calpine ORA	Opower SDG&E TURN
	3.1.3.1.2	To avoid flexible capacity, LMDR must be dispatched in a way that avoids the need for flexible capacity in the first instance. This can be accomplished by using a HT that requires the dispatch of LMR DR whenever the ISO's day-ahead forecast 3-hour net load ramp reaches the monthly maximum 3-hour net load ramp as published each May in the CAISO's annual flexible capacity needs technical study. The proposal calls for triggering LMR DR when the net load forecast ramp is expected to reach category 3 levels. This means LMR DR would be triggered when the forecast 3-hour net load ramp meets or exceeds the sum of the Base Flexibility + Peak Flexibility capacity value for that month as published in the CAISO's annual flexible capacity need technical study.	CAISO ORA Calpine	Comverge CLECA SDG&E	SCE TURN

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Category	Reference	Recommendation	Support	Oppose	Neutral
	3.1.3.1.3	Similar to 3.1.3.1.1, but recognize that additional policy changes that may be necessary to fully capture the potential flexibility benefits of LMR DR as the flexible capacity requirement policies evolve. In addition, much as it questions the need for system DR to be available in the system's off-peak months in 3.1.1.2.3.4 above, TURN questions whether flexible DR needs to be available in the months of low need for flexible capacity. That is, the requirement for DR providing flexible capacity to respond to a hard trigger could be relaxed in the months in which flexible capacity is least needed.	TURN <sup>8</sup> EnerNOC JCI CLECA SDG&E	CAISO Comverge Calpine <sup>9</sup> ORA	PG&E Clean Co SCE
Transmission and Distribution Value	3.2	There is a strong consensus for a process for how LMR DR should be valued for T&D benefits. It is recommended that this process be incorporated into the DR Cost Effectiveness Protocols when their consideration is resumed by the CPUC. Revision of these protocols is within the scope of Phase 2 of the DR Rulemaking.	CAISO Calpine Clean Co CLECA Comverge EDF EnerNOC JCI Opower ORA PG&E SCE SDG&E TURN		
Short-term Approach: Direct Distribution Deferral/Avoided Cost	3.2.3	Distribution Project specific \$/kW Locational Avoided Cost per LMR DR Program. Value associated to a specific project mitigation directly related to an LMR DR program as part of a stand-alone or element of a portfolio of solutions. Project deferrals should be larger, over \$1M; specific implementation recommendations included.	CAISO Calpine Clean Co CLECA Comverge EDF EnerNOC JCI Opower ORA PG&E SCE SDG&E TURN		

<sup>8</sup> TURN also believes this language applies to Section 3.1.3.1.2

<sup>9</sup> Calpine: DR should only count towards flexible RA requirements in the months that it is actually available.

## Load Modifying Resource Demand Response Valuation Working Group Compliance Report

Category	Reference	Recommendation	Support	Oppose	Neutral
Long Term Proposal: Direct T&D Deferral/Avoided Cost	3.2.3	Expand on the short-term approach by using increasingly granular data to identify more specific items in T&D where LMR DR could be used to mitigate the specific T&D projects. Recommendation recognizes it may be helpful to study the extent of any possible system wide benefits or passive deferrals to add a value for such, if evidenced.	Clean Co CLECA Comverge EnerNOC JCI Opower PG&E SCE SDG&E	CAISO <sup>10</sup> Calpine <sup>10</sup> ORA <sup>10</sup> TURN <sup>10</sup> EDF <sup>11</sup>	
Other Value	3.3	The Other Subgroup identified four potential additional value streams for LMR DR. It is recommended that these potential additional values and others that may be identified over time be considered in future cost / benefit calculations as appropriate.  <i>(This statement does not represent a consensus among the working group members. Some members oppose consideration of certain categories for consideration in future cost/benefit calculations as not appropriate.)</i>	CAISO Calpine Clean Co CLECA Comverge EDF EnerNOC JCI Opower ORA PG&E SCE SDG&E TURN		
Option Value	3.3.1	Option value derives from new data-driven opportunities for incorporating probabilistic statistical analysis and the covariance of factors as opposed to basing analysis on deterministic frameworks. It is expected to have a significant impact on valuation results.	CLECA EDF PG&E SDG&E Clean Co JCI SCE Comverge	Calpine <sup>12</sup> ORA	TURN Opower CAISO

<sup>10</sup> TURN, ORA, CAISO, and Calpine oppose the attribution of any passive deferral value to LM DR.

<sup>11</sup> As explained in the EDF letter that could not be included in this report due to time constraints, and to be submitted to the CPUC subsequent to the filing of this report, EDF seeks to use increasingly precise marginal cost-based tariffs, and other incentives as appropriate, to align IOU shareholder interests with state goals by providing ways for IOUs to make money from distributed energy resource deployments that avoid capacity, transmission, distribution infrastructure or other costs.

<sup>12</sup> Calpine does not oppose the consideration of option value. Calpine believes that it is already considered in the IOUs least-cost best-fit valuation models. The claim that it will have a significant impact on valuation results is unsupported and unnecessary.

(End of Appendix B)